POWER SUPPLY ECONOMICS

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NEW YORK
JOHN WILEY & SONS, Inc.
London: CHAPMAN & HALL, Limited
1934

Printed in U. S. A.

Printing
F. H. GILSON CO.
BOSTON

Composition and Plates
TECHNICAL COMPOSITION CO.
CAMBRIDGE

Binding
STANHOPE BINDERY
BOSTON

PREFACE

This book was written primarily for the executives and engineers of power companies and industrial concerns who may, in greater or less degree, be charged with the responsibility of maintaining or providing a dependable power supply.

Although the book treats of the broad general principles of the economics of power supply and does not go into technical details, it is believed that engineers charged with the investigation, design and construction of power plants and the utilization of such plants to obtain the minimum system production cost will find herein much which is of interest.

Such questions as the following are constantly before executives and engineers of power companies and industrial concerns:

1. Is our present cost of power the minimum which is obtainable with our existing facilities?

2. What additional load must we be prepared to carry next year, and year after next?

3. In order to carry this additional load, shall we build a new plant, or purchase power?

4. If additional capacity is required, shall it be steam, hydro or Diesel?

5. What shall be the capacity of the plant, and the size of the units?

6. Shall the plant be built in such a manner as to provide for increase of capacity and to what extent?

7. As an alternative to building a new plant, cannot the required capacity be installed in an old plant, perhaps at the same time rejuvenating the old plant?

8. Is it not possible to delay the construction of a new plant by making some reciprocal arrangement with a neighbor which will provide for interconnection and interchange of power, and also thus decrease power costs through the advantage of diversity?

If this book suggests to the reader methods of analysis which prove helpful in finding the most economical answer to questions such as the above, its purpose will have been achieved.

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PHILADELPHIA, PA.
August, 1933

ACKNOWLEDGMENT

This book was suggested as a result of work done by a subcommittee of the National Electric Light Association, of which one of the authors was chairman, and the authors wish to acknowledge their indebtedness to the other members of that committee: L. J. Moore, of the San Joaquin Light and Power Corporation; Farley Ralston, of the Philadelphia Electric Company; H. G. Roby, of Byllesby Engineering and Management Corporation; S. O. Schamberger, of Niagara Hudson Power Corporation; and W. F. Uhl, of Chas. T. Main, Inc., Engineers.

The authors acknowledge their indebtedness to the engineers of the Connecticut Light and Power Company, the Niagara Hudson Power Corporation, the Pennsylvania Water and Power Company, the Philadelphia Electric Company, the Public Service Corporation of New Jersey, and others, in association with whom one or both of the authors have worked on investigations and reports dealing with the economics of power supply.

The authors also wish to acknowledge their indebtedness to H. Birchard Taylor and H. P. Rust for many valuable criticisms and suggestions in connection with the chapters on "Industrial Power Plants," "Purchased Power for Industrial Plants" and "Oil Engine Plants."

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CONTENTS

CHAPTER I

DEVELOPMENT AND USE OF POWER

CHAPTER II

LOAD PREDICTIONS AND PLANNED CAPITAL EXPENDITURES

CHAPTER III

FUELS FOR STEAM POWER PRODUCTION

CHAPTER IV

STEAM POWER PLANTS

CHAPTER V

INTERNAL ECONOMICS OF STEAM POWER PLANTS

CHAPTER VI

COST OF STEAM ELECTRIC POWER

CHAPTER VII

GENERAL FACTORS CONTROLLING THE ECONOMIC UTILIZATION OF WATER POWER

CHAPTER VIII

INTERNAL ECONOMICS OF HYDRO ELECTRIC PLANTS

CHAPTER IX

ECONOMIC FUNCTIONS OF HYDRO ELECTRIC PLANTS

CHAPTER X

COST OF HYDRO ELECTRIC POWER

CHAPTER XI

VALUE OF HYDRO ELECTRIC POWER

CHAPTER XII

PEAK LOAD PLANTS

CHAPTER XIII

INTERCONNECTION AS AN ELEMENT AFFECTING THE COST OF POWER

CHAPTER XIV

OIL ENGINE PLANTS

CHAPTER XV

INDUSTRIAL POWER PLANTS

CHAPTER XVI

PURCHASED POWER FOR INDUSTRIAL PLANTS

POWER SUPPLY ECONOMICS

CHAPTER I

DEVELOPMENT AND USE OF POWER

1. Effect of Power on Productivity. — Power is the principal factor which makes the world of today so greatly different from the world of yesterday. Until some 200 years ago, man's efforts to increase his productivity were relatively feeble, but from then on his use of power for saving time in transportation and in the making of articles which he required increased rapidly. The saving in time thus obtained gave him more leisure, which engendered new wants, which it required more power to satisfy, and thus the increase in the use of power went on at an accelerating rate to the present day. The commercial development of electric power during the past 50 years, with its greater flexibility, has given special impetus to this acceleration.

The application of power to machines previously operated by hand led to a vast improvement in the efficiency of the machines themselves. Consequently, estimates of the increase in man's productivity due to the use of power are mere guesses. In the United States, the total power utilized in transportation, in industry and in the home is something over 100 times the power which could be exerted by man unaided by this genie which he has created. Thus, man's productivity has been increased something more than 100 times by the introduction of power. This increase in productivity has caused and is still causing profound changes in the social and economic structure of society.

Much twaddle has been written about the machine age, robots, logical unemployment, technocracy, etc. The simple truth of the matter is that the advent of power is releasing man from drudgery, giving him more leisure, more wealth, health and comfort, and stimulating his creative thought. To be convinced of the truth of this assertion, one has only to do a little reading of serious history and contrast the state of the average

man in a country like America with that of the same average man in the same country 200 years ago. Or if he has a distaste for history, let him visit a country like China where power is not yet fully enthroned and contrast the condition of common man there with that of the common run of men in his own country.

2. First Use of Power. — Back in the dim ages of antiquity before the time of authentic history, man first began the use of power for the mitigation of human labor. Animal power for

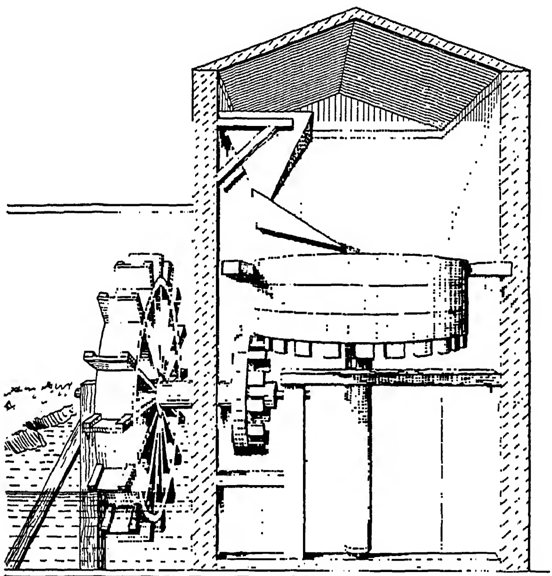


FIG. 1. Early Roman water wheel used for grinding grain as described by the Roman Engineer Vitruvius (about 14 B.C.). From the Journal of the Franklin Institute, Vol. CXL, page 177 (Sept. 1895).

raising water and grinding corn was probably the first power utilized; next came the utilization of water power and wind power.

Along the great rivers, such as the Ganges, Nile, Euphrates and Yellow River, where the ancient civilizations flourished, simple current wheels similar to the noria, which is still in use in China, driven directly by the current of the stream, were used to raise water for irrigation, for drinking purposes and for furnishing power for operating crude mills for grinding grain. A Roman water wheel of this type for grinding grain is shown in Fig. 1.

3. Development of Water Power. — Progress in the utilization of water power was very slow for thousands of years, but important improvements were made in Germany, France and England during the sixteenth, seventeenth and eighteenth centuries. In 1581, a series of great float wheels was installed on the Thames River near London Bridge, operating plunger pumps for the first water supply of the City of London.

After the float wheel came the undershot and breast wheels, and finally the overshot wheel, all of which required the use of artificial water channels for delivering the water to the prime mover. The turbine and the impulse wheels are both developments of the past century.

During the seventeenth and eighteenth centuries, mills operated by water power had become quite common in Western

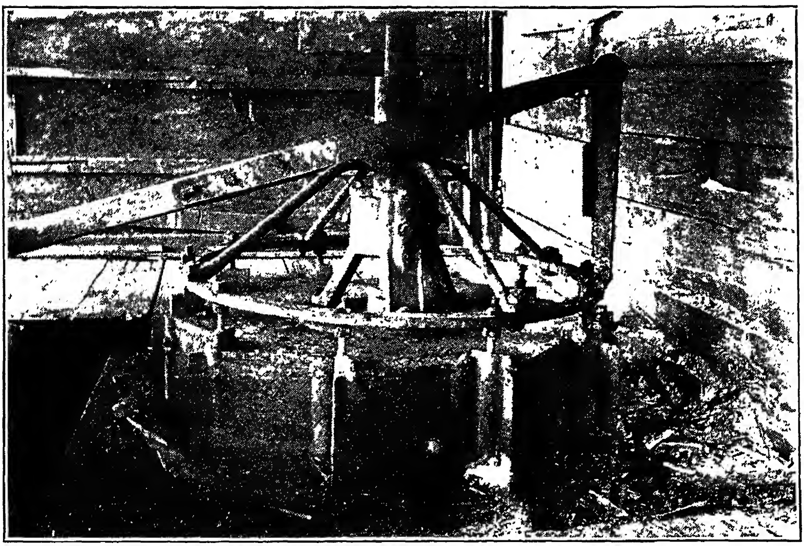


FIG. 2. Early American turbine. Note slide gates and method of operation. Courtesy of Forest Nagler, Chief Engineer, Canadian Allis-Chalmers, Ltd.

Europe and Great Britain. The power obtained was generally utilized for grinding grain. At the close of the eighteenth century, with the invention of the power loom by Cartwright (1785), it was utilized in the weaving of cloth. From then on, the development of water power went on rapidly, paralleling that of steam.

With the development of electricity during the past 50 years, and particularly with the advent of electrical transmission, it became in many cases economically practicable to transmit power from distant water power sites to existing centers of population, thus tremendously broadening the field in which such power could be economically utilized.

4. Wind Power. — The utilization of wind power for pumping water and grinding grain was probably begun almost as soon as the use of water power. The use of wind power was an important factor in the industrial development of the Low Countries during the middle ages. Development in the use of wind power has, however, been comparatively insignificant within historical times. Possibilities of utilizing the wind in a sufficiently economical manner to make it in some cases a feasible source of power on a large scale still exist and may be developed.

5. Development of Steam Power. — Although the beginnings of steam power date at least from Hero's Engine (150 B.C.), unlike wind power and water power, it did not attain economic importance until the end of the eighteenth century. To Thomas Newcomen (1711) probably belongs the credit of constructing the first practicable steam engine, but the device did not attain economic importance until the advent of James Watt in 1763, who invented many improvements including the condenser, the use of steam on both sides of the piston, the throttle valve, the automatic governor and other features.

From the time of Watt down to the present day, the development and improvement of steam power have been rapid. In the United States, approximately 71 per cent of the prime movers in central stations are operated by steam.

6. Development of Internal Combustion Engines. — The first practicable internal combustion engine appears to have been constructed by W. Cecil in 1820 utilizing a hydrogen-air mixture. Shortly thereafter, Samuel Brown developed commercial gas engines and in 1826 even utilized one as the motive power for a road vehicle. Important developments were made by Otto, and Burnett and Priestman applied the internal combustion engine to the utilization of oil. Gottlieb Daimler, 1883, was the first to use light oils (petrol or gasoline) successfully in internal combustion engines. Previous to his development, internal combustion engines weighed about 1100 lb per bhp and made about 200 revolutions per minute. In 1886 Daimler built an engine

weighing 88 lb per bhp and making 800 rpm. From then on the development was rapid, and today a modern Diesel uses about one-fifth of the fuel per bhp that was required in some of the early gas engines.

To a Frenchman, Nicholas Cugnot, 1771, belongs the credit of producing the first automobile, a steam driven horseless carriage. Automobiles powered by internal combustion engines did not, however, attain commercial importance until after 1890.

During the last 30 years, the internal combustion engine has developed to great commercial importance, and owing to the phenomenal growth in the use of automobiles, trucks and buses, the installed capacity of internal combustion engines greatly exceeds the installed capacity of all other prime movers combined. Internal combustion engines have also been successfully used for driving ships and as prime movers in factories, but they have not been used to any great extent in large central station power plants.

7. Development in Use of Electric Power. — Without the flexibility and convenience of electricity, the developments listed in the use of power would have been quite different and much less extensive than they have been. Michael Faraday (1831) invented dynamos and motors, but the electric power industry was born with the founding of the New York Edison Company in 1883 by Thomas Edison to generate and distribute electricity for use in his incandescent lamps which he had invented in 1879. He was also responsible for many improvements in dynamos, in motors and in electrical distribution.[1]

From this small beginning, the electric power industry has developed to its present size, representing capital investment of some ten billion dollars in America alone. A huge investment, to be sure, but a somewhat smaller one than the nation's investment in automobiles.

8. Total Power in the United States. — Most people when they think of power think of the central station and the power company, although only about 4 per cent of the power installation in the United States is central station power. Over 90 per cent of the power installation in the United States is used in transportation — automobiles, trucks, buses and railroads. Industry

[1] Electric arc lighting had already been introduced, and an electric arc light was installed in a lighthouse at Dungeness in 1862 and operated for many years.

TABLE 1

INSTALLATION AND ENERGY OUTPUT STATISTICS FOR VARIOUS COUNTRIES

Data Are for Central Stations Only, Except for Countries Marked (*), in Which Cases All Capacity and Output Are Included

1 Country	2 Year of Statistics	3 Steam Plants, kw (*a*)	4 Hydro Electric Plants, kw	5 Total Installation kw (*b*)	6 Population (*c*)	7 Total per Capita Installation, kw	8 Total Energy Output in Year, Million kwhr (*a*)	9 Energy Output per Capita for Year, kwhr	10 Annual Capacity Factor
United States (*a*)	1931	23,823,017	8,806,096	32,629,113	124,070,000	0.26	85,575	690	0.30
Germany	1929	4,960,000	740,000	5,700,000	64,036,000	0.09	12,444	194	0.25
Canada (*f*)	1930	178,000	3,580,000	3,758,000	9,935,000	0.38	16,100	1,610	0.49
France* (*h*)	1931	5,607,120	2,872,400	8,479,520	41,400,000	0.20	15,150	366	0.20
Great Britain (*d*)	1929-30	6,197,225	403,000	6,600,225	46,189,000	0.14	10,550	229	0.18
Italy (*g*)	1931-32	600,000	3,858,000	4,458,000	41,145,000	0.11	10,300	250	0.26
Japan* (*e*)	1929	1,540,044	2,581,949	4,121,993	90,395,000	0.05	11,962	132	0.33
Norway*	1927	....	1,579,086	1,579,086	2,810,000	0.56	8,000	2,850	0.58
Russia*	1927	1,440,000	250,000	1,690,000	147,014,000	0.01	4,112	28	0.28
Sweden*	1927	295,000	1,100,000	1,395,000	6,142,000	0.23	4,350	709	0.36
Switzerland* (*c*)	1927	....	2,530,000	2,530,000	4,067,000	0.62	4,650	1,140	0.21
Belgium	1925	1,390,000	....	1,390,000	8,129,000	0.17	3,160	390	0.26
Austria	1925	550,000	450,000	1,000,000	6,713,000	0.15	2,500	405	0.28
Poland	1926	....	....	1,000,000	31,104,000	0.03	1,900	61	0.22
Mexico	1926	75,800	340,000	415,800	16,404,000	0.02	1,400	87	0.38
Czecho-Slovakia	1926	666,000	114,000	780,000	14,726,000	0.05	1,300	93	0.19
Holland	1927	665,380	....	665,380	7,920,000	0.08	1,200	152	0.21
New Zealand	1927	35,627	103,288	138,915	1,506,000	0.09	540	360	0.44
Roumania*	1927	....	....	230,000	18,326,000	0.01	500	27	0.25
Dutch East Indies	1927	129,000	61,000	190,000	60,731,000	....	500	8	0.30
Denmark	1926-27	229,000	....	229,000	3,542,000	0.06	422	119	0.21
Finland	1926	....	175,000	175,000	3,634,000	0.05	360	99	0.23

NOTES: When not otherwise noted, data in Columns 2, 3, 4, 5, and 8 are from "Power Resources of the World," World Power Conference, London, 1929.
* Includes all plants, private, public supply and industrial. For other countries, plants recorded are supposedly limited to central stations as for United States statistics.
(*a*) For United States, National Electric Light Association Statistical Bulletin 7, 1932.
(*b*) Does not include internal combustion engines.
(*c*) Commerce Year Book, 1931, Vol. II, U. S. Department of Commerce.
(*d*) Electrical World, Aug. 8, 1931, page 258.
(*e*) Electrical World, Aug. 8, 1931, page 258.
(*f*) Based on data for Canadian Year Book, 1932.
(*g*) Based on Electrical World, June 25, 1932, output partly estimated.
(*h*) Report of Minister of Public Works "Statistique de la production et de la distribution de l'energie electrique," January 1, 1931, output partly estimated.

makes about 50 per cent of the power which it utilizes in its factories, and purchases the other half from central stations.

Power installation in the United States totals about 880,000,000 kilowatts, divided approximately as follows:

Central stations	32,000,000 kw
Private industrial power plants	15,000,000 kw
Railroads	90,000,000 kw
Automobiles, buses, trucks, etc.	743,000,000 kw

9. Use of Central Station Power in Various Countries.— Table 1 gives some power statistics for some of the leading countries of the world. For many of the countries the data for central stations only are given, but as noted, the data for France, Japan, Norway, Russia, Sweden and Switzerland include all power, industrial stations as well as central stations. Any conclusions as to the relative industrialization of the various countries based merely on these statistics would be erroneous, because the percentage of central station power utilized in industry varies greatly in different countries. Thus, whereas in the United States about one-half of the power used in factories is produced in the individual power plants of the factories, the proportion so produced in Great Britain and Germany, for instance, is very much greater. The installation per capita in the United States is shown to be 0.26 kw, whereas in Canada, where statistics are on the same basis, the installation is 0.38 kw per capita, or about 50 per cent more. It is also interesting to note that in countries where water power installations predominate (such as Canada, Norway and Switzerland), the per capita use of energy is generally much greater than in the United States where steam power plants form about 71 per cent of the total installation.

Capacity factors also are shown to be generally higher in countries where water power developments predominate. However, no hasty conclusions should be drawn from these statistics, particularly with regard to capacity factors. These statistics, as well as those given in Table 2 for the individual states of the United States, do indicate that, in countries or sections where water power is abundant, there is in general a much greater per capita use of electrical energy than in sections not so favored.

TABLE 2

INSTALLATION AND ENERGY OUTPUT STATISTICS FOR THE UNITED STATES, 1930. (CENTRAL STATIONS)

	1 Steam Plants, kw (a)	2 Hydro Electric Plants, kw (a)	3 Internal Combustion Plants, kw (a)	4 Total Installation, kw (a)	5 Population (b)	6 Total per Capita Installation, kw (c)	7 Total Energy Output in Year, Million kwhr (a)	8 Energy Output per Capita for Year, kwhr (c)	9 Annual Capacity Factor (c)
Total United States........	23,427,058	8,206,732	416,139	32,049,919	122,775,046	0.26	88,592	720	0.32
Maine......................	70,670	205,956	812	277,438	797,423	0.35	699	880	0.29
New Hampshire............	42,005	211,163	1,400	254,568	465,293	0.55	365	785	0.16
Vermont...................	14,860	160,418	....	175,278	359,611	0.49	472	1,320	0.31
Massachusetts.............	981,335	128,860	3,065	1,113,260	4,249,614	0.26	2,550	590	0.27
Rhode Island..............	241,200	1,750	....	242,950	687,497	0.35	547	800	0.26
Connecticut...............	469,040	77,405	480	546,925	1,606,903	0.34	1,199	745	0.25
Total New England........	1,819,110	785,552	5,757	2,610,419	8,166,341	0.32	5,832	715	0.25
New York..................	3,062,235	1,006,062	9,568	4,077,865	12,588,066	0.32	11,336	906	0.32
New Jersey................	906,665	950	1,740	909,355	4,041,334	0.22	2,824	700	0.36
Pennsylvania..............	2,308,670	216,650	9,841	2,535,161	9,631,350	0.26	7,844	812	0.35
Total Middle Atlantic......	6,277,570	1,223,662	21,149	7,522,381	26,260,750	0.29	22,004	845	0.34
Ohio......................	2,242,366	12,675	2,360	2,257,401	6,646,697	0.34	5,798	865	0.29
Indiana...................	871,120	34,820	3,807	909,747	3,238,503	0.28	2,857	880	0.36
Illinois....................	2,269,234	46,240	4,565	2,320,039	7,630,654	0.30	6,821	900	0.34
Michigan..................	1,285,095	215,715	6,857	1,507,667	4,842,325	0.31	3,991	825	0.30
Wisconsin.................	568,189	247,143	6,988	822,320	2,939,006	0.28	2,156	740	0.30
Total East North Central..	7,236,004	556,593	24,577	7,817,174	25,297,185	0.31	21,623	855	0.31

TABLE 2 (*Continued*)

INSTALLATION AND ENERGY OUTPUT STATISTICS FOR THE UNITED STATES, 1930. (CENTRAL STATIONS)

	1 Steam Plants, kw (a)	2 Hydro Electric Plants, kw (a)	3 Internal Combustion Plants, kw (a)	4 Total Installation, kw (a)	5 Population (b)	6 Total per Capita Installation, kw (c)	7 Total Energy Output in Year, Million kwhr (a)	8 Energy Output per Capita for Year, kwhr (c)	9 Annual Capacity Factor (c)
Minnesota	279,064	130,766	8,754	418,584	2,563,953	0.16	1,127	440	0.31
Iowa	375,864	152,003	21,317	549,184	2,470,939	0.22	1,534	620	0.32
Missouri	570,952	12,800	23,682	607,434	3,629,367	0.17	1,269	350	0.24
North Dakota	53,645	....	3,650	57,295	680,845	0.08	125	184	0.25
South Dakota	44,958	4,200	12,355	61,513	692,849	0.09	114	164	0.21
Nebraska	192,734	10,546	23,416	226,696	1,377,963	0.16	567	412	0.29
Kansas	325,822	7,582	36,794	370,198	1,880,999	0.20	1,002	534	0.31
Total West North Central	1,843,039	317,897	129,968	2,290,904	13,296,915	0.17	5,738	432	0.28
Delaware	31,350	....	915	32,265	238,380	0.13	18	760	0.64
Maryland	338,160	271,985	2,622	612,767	1,631,526	0.38	1,862	1,140	0.34
District of Columbia	178,000	....	....	178,000	486,869	0.37	504	1,030	0.32
Virginia	335,204	85,402	5,201	425,807	2,421,851	0.17	1,231	510	0.33
West Virginia	463,122	56,305	4,137	523,564	1,729,205	0.30	2,021	1,170	0.44
North Carolina	341,195	346,500	3,404	691,099	3,170,276	0.22	2,262	460	0.19
South Carolina	147,398	536,155	520	684,073	1,738,765	0.39	....	......	......
Georgia	134,969	275,762	2,035	412,766	2,908,506	0.14	1,017	348	0.28
Florida	324,173	14,450	25,385	364,008	1,468,211	0.25	678	455	0.22
Total South Atlantic	2,293,571	1,586,559	44,219	3,924,349	15,793,589	0.25	9,593	605	0.28
Kentucky	218,772	105,160	8,602	332,534	2,614,589	0.13	688	264	0.24
Tennessee	205,525	128,698	2,978	337,201	2,616,556	0.13	837	320	0.28
Alabama	238,500	411,522	3,951	653,973	2,646,248	0.25	1,759	665	0.31
Mississippi	42,747	....	11,984	54,731	2,009,821	0.26	62	31	0.12
Total East South Central	705,544	645,380	27,515	1,378,439	9,887,214	0.14	3,346	338	0.28

TABLE 2 (*Concluded*)

INSTALLATION AND ENERGY OUTPUT STATISTICS FOR THE UNITED STATES, 1930. (CENTRAL STATIONS)

	1 Steam Plants, kw (a)	2 Hydro Electric Plants, kw (a)	3 Internal Combustion Plants, kw (a)	4 Total Installation, kw (a)	5 Population (b)	6 Total per Capita Installation, kw (c)	7 Total Energy Output in Year, Million kwhr (a)	8 Energy Output per Capita for Year, kwhr (c)	9 Annual Capacity Factor (c)
Arkansas	75,715	10,855	7,364	93,934	1,854,482	0.05	108	58	0.13
Louisiana	249,600	......	14,084	263,684	2,101,593	0.12	1,066	510	0.46
Oklahoma	305,681	1,700	30,056	337,437	2,396,040	0.14	958	400	0.32
Texas	840,060	6,595	65,073	911,728	5,824,715	0.16	2,915	500	0.36
Total West South Central	1,471,056	19,150	116,577	1,606,783	12,176,830	0.13	5,047	414	0.36
Montana	8,085	300,414	1,779	310,278	537,606	0.58	1,320	2,460	0.49
Idaho	750	203,986	770	205,506	445,032	0.45	801	1,800	0.45
Wyoming	24,709	2,982	3,116	30,807	225,565	0.14	56	250	0.21
Colorado	148,569	52,107	1,678	202,354	1,035,791	0.20	526	507	0.30
New Mexico	34,227	981	7,665	42,873	423,317	0.10	76	180	0.20
Arizona	32,727	87,450	18,145	138,322	435,573	0.32	381	870	0.31
Utah	41,000	100,840	3,268	145,108	507,847	0.29	293	580	0.23
Nevada	350	10,791	1,436	12,577	91,058	0.14	43	470	0.40
Total Mountain	290,417	759,551	37,857	1,087,825	3,701,789	0.29	3,496	950	0.37
Washington	178,627	585,632	999	765,258	1,563,396	0.49	2,528	1,610	0.38
Oregon	170,220	155,704	1,479	327,403	953,786	0.34	1,201	1,260	0.42
California	1,141,900	1,571,052	6,032	2,718,984	5,677,251	0.48	8,187	1,440	0.34
Total Pacific	1,490,747	2,312,388	8,510	3,811,645	8,194,433	0.47	11,916	1,450	0.36

NOTES: (a) From Statistical Bulletin of National Electric Light Association. (b) U. S. Bureau of Census. (c) Computed.

10. Use of Central Station Power in the United States. — In compiling Table 2, installation and output figures for the year 1930 were utilized, although later figures were available, because it was desired to use these figures in conjunction with the figures for the population of the various states which are taken from the census of the United States for the year 1930. Installation and output figures are from Statistical Bulletin 7, 1931, of the National Electric Light Association, and the data on installation per capita, energy output per capita and annual capacity factor are computed.

The per capita statistics for a few states, such as Vermont, Maryland and West Virginia, are somewhat misleading because of the large export of power from these states. The capacity factor shown for Delaware is misleading because of relatively large imports of power. As a rule, the states which have a relatively large percentage of hydro show the highest installation and energy output per capita, such as New Hampshire, Vermont, Montana, Idaho and Washington. Montana leads the rest of the states in energy output per capita, showing an output of 2460 kwhr per capita, and Mississippi has the lowest — 31 kwhr per capita.

11. Modern Tendencies in Use of Power. — At the present time, development is going forward in all the three principal sources of power supply — internal combustion engines, steam plants and hydro electric plants. It cannot be said that there is any present tendency toward the use of one particular kind of power to the exclusion of other types, as sometimes one type will work out as the most economical, and sometimes another, and even more frequently, a combination of two or more kinds of power supply works out more economically than either one alone. As will be shown later in the book, steam, hydro and internal combustion engines are usually complementary sources of power supply, rather than being competitive, as is so frequently assumed.

There is a regrettable tendency on the part of some power engineers, and even of some executives, to divide into schools, one advocating the use of hydro electric power wherever possible; another steam; and another internal combustion engines, the disciples of each school including, of course, the manufacturers of each particular type of prime mover and their employees. When a factory or a public utility requires additional power

supply, too many of those charged with the responsibility of making the necessary decisions approach the problem from the standpoint of advocates who feel compelled to prove that the particular scheme with which they happen to be most familiar will produce the most economical results.

Some of these advocates stop just short of becoming ridiculous. For instance, no steam man would advocate the removal of internal combustion engines from automobiles and the substitution therefor of steam engines, and no internal combustion man would advocate the use of gasoline engines as the prime movers in a large central station power plant.

All these various types of prime movers have their particular field which may frequently overlap the field of one or more of the other types of prime movers. In any particular situation, it is possible with the aid of data which are usually readily obtainable to make an economic analysis, and as a result thereof to determine the most economical source of power supply to utilize in any given case. For such work, however, freedom from prejudice and a judicial attitude of mind are essential.

12. General Economic Considerations Leading to a Choice of Power Supply. — Among the general factors to be considered in connection with the problem of determining the most economical source of power supply are: location, cost of various types of fuels, size of the required installation, degree of reliability of service required, availability of water power sites, availability of condensing water supply, cost of purchased power and use of process steam.

Location as Affecting Choice of Power Supply. — Location is usually a very important consideration which affects the problem in many ways. If a factory is located in a city where property values are high, the cost of space for any type of individual power plant may be so great that it pays to purchase from a central station the power requirements. Thus in certain cities, it used to be customary for all the large office buildings to have their own individual power plants, using the exhaust steam for heating purposes and furnishing to the tenants of the building their requirements of light and power. More recently the owners of such buildings in these cities have found in many cases that because of high rental value of their space it is, in those particular situations, more economical to purchase both steam and electric power than to install their own individual plants.

If a factory or a power company is situated at or near a water power site, it may be economical for it to supply a part or all of its requirements by the development of water power. A power company whose plants are near or adjacent to a supply of coal, oil or natural gas may find it more economical to supply all or most of its requirements by steam power even though favorable water power sites may be available also.

Cost of Fuel as Affecting Choice of Power Supply. — The cost of various kinds of fuel is also important. If coal is cheap, this is one factor which favors the use of a steam plant. If gas or oil is cheap, it may influence the decision in favor of either steam or internal combustion engines. A low cost of fuel is unfavorable to the use of hydro electric power, although it has been found in the case of many large power systems having the advantage of low fuel cost that even under such circumstances it pays to utilize some hydro electric power provided that favorable sites not too far distant from their load centers are available.[2]

For both industrial plants and public utilities, the size of the required installation sometimes materially affects the choice of the next increment of power supply. Thus, a hydro site may be very attractive, but the installation required to obtain a development of reasonable cost may be much greater than needed to take care of present load conditions.[3] On the other hand, a steam plant may be built of any desired capacity and units may be added from time to time of a size just sufficient to take care of the growth in load from year to year plus the necessary reserve requirements. Similarly, for meeting the power requirements of relatively small factories and towns, the use of oil and Diesel engines is sometimes advisable because of relatively low capital cost of such plants in small units.

Reliability of Service as Affecting Choice of Power Supply. — If an extremely high reliability of service is required, power which is transmitted from a distant point over a single transmission line should be limited to a total amount not greater than the normal reserve requirements of the system. That is, if from any cause the transmission service was interrupted at time of peak load, there should still be sufficient reserve capacity to permit of carrying the load. In many situations, this condition tends to limit the use of power transmitted from a distance.

[2] See Chapter VII, Section 110.

[3] See also Chapter XI, Section 159.

In other cases where the necessity for extreme reliability is not so great, this condition has little effect on the choice of power supply. The same considerations apply to the factory which is contemplating installing its own industrial power plant. If the operations are of such a nature that an interruption in power supply is not very costly, a factory may find it economical to have its own power plant of a capacity just sufficient to supply its load. On the other hand, if continuity of service is of great importance in the operation of the factory, it would be necessary for the factory to have a power plant with a capacity equal to perhaps twice the demand that may come upon it. Such a requirement is often the deciding factor leading to the decision of a factory management that central station power will prove a more economical source of power supply for its particular conditions.

Occasionally a small factory owner is led to discontinue the use of central station power and install an oil engine of a capacity sufficient to meet his load requirements amply. If continuity of service is of importance in his operations, the indicated saving is sometimes more apparent than real, as he has no reserve capacity and the economics of the situation might have appeared quite different if the proposed factory power plant had consisted of two oil engines, either of which had sufficient capacity to carry the load.

Availability of Water Power Sites as Affecting Choice of Power Supply. — If suitable water power sites are available not too far distant from the load, the economic feasibility of utilizing them for a source of at least a part of the required power supply should be thoroughly investigated. Even in sections of the country where cheap coal is abundant, it is usually economical to utilize some water power when available for a portion of the power supply of a large system. Sometimes individual mills and factories find it economical to utilize some water power when readily available.

Availability of Condensing Water as Affecting Choice of Power Supply. — The availability of a plentiful supply of condensing water is an important consideration in determining the most economical source of power supply. A factory located on a river may find it economical to have its own steam plant, whereas the same factory if located at a point where a plentiful supply of condensing water was not available might find it more economical to buy central station power.

Cost of Purchased Power as Affecting Choice of Power Supply. — It is axiomatic that the cost of purchased power should be a very important consideration in determining the most economical source of power supply in any given situation, and still this factor is frequently not given the consideration which it should receive. Any power company or any factory should prefer to purchase power if this can be done at a cost equal to or less than what it could make it for if it built its own plant. Usually one can afford to pay a little more for purchased power than the cost of power from a proposed plant which he is contemplating building, because he may thus avoid going further into debt, and at any rate avoids a material capital expenditure. It is a relatively simple matter to determine what purchased power will cost in any given situation, but when one builds a plant the total cost of the energy from that plant may or may not be that which was estimated in advance of construction.

It should be a constant rule of good business practice which should hold equally for manufacturers and power companies never to build a power plant for meeting an increased demand for power until after all the possibilities for purchasing the required additional power have been considered and thoroughly analyzed. Personal pride and a desire for "a place in the sun" have led to the construction of many power plants by both manufacturers and public utilities which a thorough and calm economic analysis could not have justified. The receiverships which have followed some of these ambitious construction schedules should serve as a warning to anyone tempted to follow suit.

Process Steam as Affecting Choice of Power Supply. — In the case of factories which use steam in connection with their processes, a steam plant may be constructed to supply their power requirements and at the same time furnish process steam as a by-product. The necessity for process steam is frequently the deciding factor in making it more economical for a factory to build its own steam plant, rather than purchase power from a central station. Some of the public utilities are meeting this situation by offering to sell the factory both steam and power.

13. Necessity for More Careful Analysis of Present Practices. — In a majority of cases, decisions to build power plants, and decisions as to the type and capacity of plant to be built, are not based on a calm and thorough analysis of all the economic factors

involved. Personal prejudice or desire to have the biggest and best have frequently played an important part in making such decisions. Both power companies and factories are frequent offenders against the laws of economics in this respect, and it is not an uncommon spectacle to find a power company erecting a large power plant which its normal increase in business would not load up to capacity for many years to come, even when it is known that a neighboring company will have excess capacity for some years in the future.

In many such cases it would prove economical for the company with the surplus capacity to sell capacity and energy to its neighbors for several years or until its own load required the use of such excess capacity. At that time the other company should build a plant, and the arrangement would be reversed. In a number of cases, interconnection agreements have been worked out with material advantage to all parties concerned.[4] The same thing holds with regard to individual factories when their power requirements increase beyond the safe capacity of their existing power plants. Under such circumstances, it is frequently economical to buy the increased requirements of power for several years until the increase has become sufficient to load up an additional proposed unit in the power plant. Such a course is often economical even though the unit cost of the purchased power is materially higher than the average unit cost of power made in their own plant.

Many executives and engineers are prejudiced in favor of hydro power or of steam power or of particular types of plants, and permit such prejudices to influence their judgment. Some power company executives seem to feel that, because the price of fuel has declined to a marked degree during the past few years and because there has been a truly remarkable increase in the efficiency of steam generation, necessarily steam is practically always cheaper than hydro. On the other hand, there are other executives who are known as hydro men and who will build a hydro plant whenever there is the least possible excuse for it. Except in rare cases, there is no open and shut case for either steam or hydro. Any executive who neglects to have a thorough, calm and complete economic analysis made whenever there is a need for additional power supply neglects an opportunity to make really big money for his company. Decision as to large

[4] See Chapter XIII.

capital expenditures is one of the most important of executive functions, and wisely conceived capital expenditures go a long way to make up the difference between the mediocre corporation and the most efficient.

Not all power engineers are fitted to be entrusted with the necessary economic analysis in a case of this kind. In the first place, engineers as a class are predisposed to spend money. They like to build something and are frequently fired with an ambition to design and build something which is a little better, finer, bigger or more efficient than what somebody else has. Such a problem cannot always be safely entrusted to an engineering construction organization because for the reasons stated above they are prone to come out of their investigation with a report recommending a major capital expenditure. Some utility holding companies maintain a group of experts for the prime purpose of analyzing proposed capital expenditures and determining the most economical course to pursue for each particular case. In many cases, however, where the decision may involve large capital expenditures, it is highly advisable to engage the services of an outside consultant of broad experience and unprejudiced mind to report on the most economical course to pursue.

14. Material Savings Possible in Cost of Power. — When a decision has been reached as to whether or not a power plant is required and what type and capacity of plant is to be built, there is usually no material difficulty remaining as many organizations are available which are entirely competent to design and construct power plants of every kind once these primary decisions are reached. A great deal of talent is utilized in determining details of design and construction when perchance no plant at all should have been constructed. Material savings in operation and in capital expenditures are possible if each situation is carefully analyzed. A new plant may be highly efficient and have a very low production cost, and by going to the largest sized units even higher efficiencies and lower production costs may be attained, but the maximum economy is secured when the total operating cost of the system plus the fixed charges on the proposed new capital expenditures is always at a minimum.

CHAPTER II

LOAD PREDICTIONS AND PLANNED CAPITAL EXPENDITURES

15. Necessity for Making Load Predictions. — In order that any power company may be able to determine the necessity or desirability of adding additional generating capacity to the system, it is essential that it should at all times have as accurate a forecast of the future load of its system as it is practicable to obtain. Even though five year forecasts of future loads made three or four years ago may look rather ridiculous in the light of recent events, that is no reason for abandoning the practice of predicting loads for some years in the future in order to have some basis aside from hunches on which to base decisions as to the providing of additional facilities.

Some of the larger power companies and holding companies maintain a staff of men specially trained in making load prediction studies. If a company makes thorough studies of this kind and supplements them with economic studies, and then schedules its capital expenditures in such a manner that the facilities provided are kept just a little ahead of the current year's requirements, it is always in a position to furnish adequate service to its customers and to take care of the growth in load. At the same time, a company which follows this procedure is able to keep its fixed charges close to the practicable minimum.

When utility securities were much in demand, some power companies yielded to temptation and provided facilities far in advance of current needs, being to some extent actuated by a desire for the biggest and best in the line of power plants and other facilities; as a result many such companies are now groaning under an undue load of fixed charges.

16. Growth in the Use of Central Station Power in the United States. — The electric power industry has had a phenomenal growth in the United States, as indicated by Fig. 3, which shows graphically the growth in energy, output, installation and popu-

lation from 1912 to 1931 inclusive. It will be noted that, during the period, while population increased 30 per cent, the output of electrical energy increased about 700 per cent, and installation increased about 540 per cent.

Figure 3 shows that, whereas in 1912 about 53 per cent of the total installation was steam and 47 per cent hydro, since that

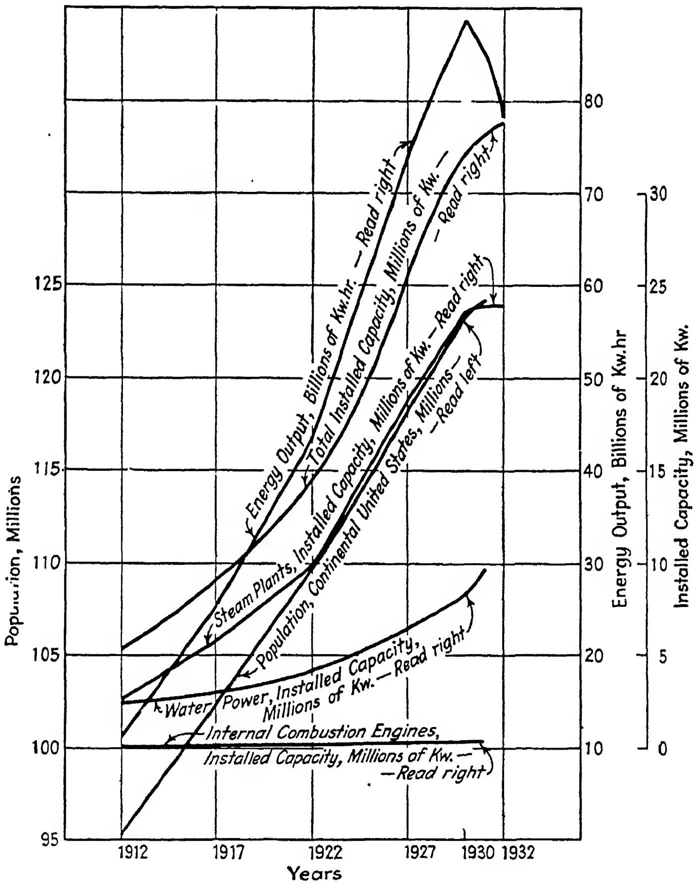


FIG. 3. Growth of energy output, installation and population in United States. Note: output and installation are for central stations only. Basic data are from U. S. Census and Statistics and National Electric Light Association.

time the rate of increase in steam capacity has been greater than in hydro until in 1930 hydro installation comprised but 26.6

per cent of the total installation. It should also be noted, however, that in recent years the rate of increase in hydro capacity has shown some increase, for the curve has become steeper, although there has been no acceleration in the rate of increase of steam installation. This is interesting, because it is contrary to the general belief.

17. Annual Capacity Factors in the United States and Per Capita Use of Central Station Power. — In Fig. 4 are shown

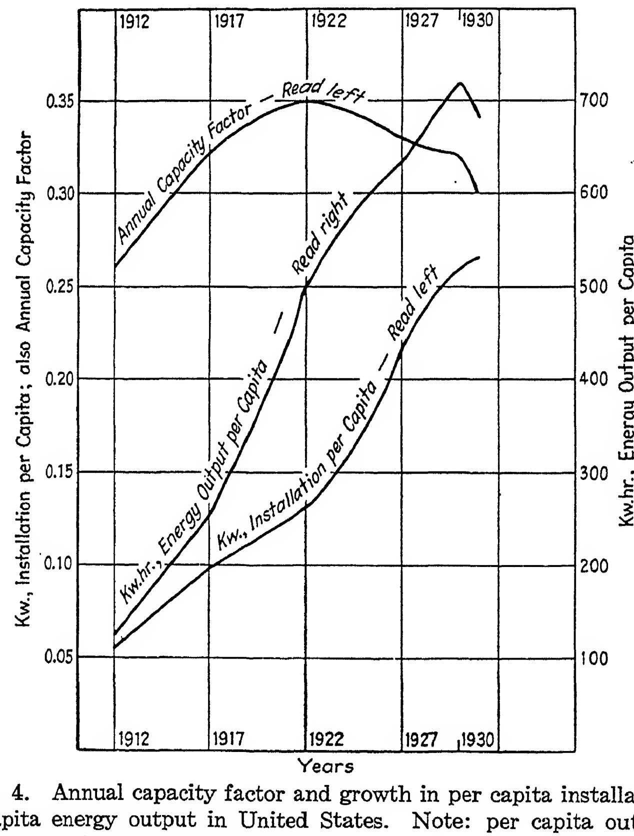


FIG. 4. Annual capacity factor and growth in per capita installation and per capita energy output in United States. Note: per capita output and installation is for Central Stations only.

graphically the annual capacity factors and the growth in per capita installation and per capita energy output in the United States. It will be noted that the energy output per capita has risen steadily from 122 kwhr per capita in 1912 to 720 in 1930, after which it took a sharp drop owing to the unprecedented

depression. The installation per capita is shown to have increased steadily throughout the period.

Throughout the history of the power industry, the load factors of practically all load curves have been improving on account of greater diversity in the component loads. With combinations into larger systems and the interconnection between others, the necessary reserve requirements have decreased, and more efficient use of capacity has become practicable. Consequently, one would expect to find throughout the period a parallel increase in capacity factors. It is rather surprising, therefore, to find that the annual capacity factor for the whole country was only a little higher in 1931 than it was in 1912. Beginning with 1912, with a capacity factor of 26 per cent, the curve mounts rapidly, until in 1922 we find that the annual capacity factor reached 35 per cent, but that after that year it rapidly slumped off until in 1931 the annual capacity factor was only 30 per cent. Clearly the industry has consistently overbuilt since 1922.

Even if we allow for the fact that, 1922 being a year of depression (a relatively mild one in the light of more recent experience), some needed construction was postponed, it would appear that with the further combination and interconnection which have been effected since then, the total installation could have been held down to a point which would have given an annual capacity factor of at least 35 per cent. Of course, after output of energy began to decline in 1931, no control was possible. Based on a 37 per cent capacity factor, which seems practicable for present day conditions, the industry in 1931 had sufficient capacity installed to take care of an energy output of 106 billion kwhr, which is 24 per cent in excess of the actual or enough for nearly three years' normal growth.

18. Growth of Load in Individual Systems. — The growth in the annual peak loads of all power systems was practically continuous for many years, and there is every indication that the market for additional uses of electric power is by no means saturated. Domestic appliances and air conditioning are two fields of application which offer vast possibilities. The electrification of industry has apparently not yet approached the saturation point (see Fig. 9), as during the past ten years or so practically all the increase in factory power has been due to greater purchases of central station power.

In Figs. 5 and 6 are presented curves for a number of power systems showing the growth in annual peak loads over a period of years. With the advent of the great depression after 1929, the curves in general show a recession to lower peaks, or remain practically without change, as that of the New York Edison Company. As indicated above, there is reason to think that the depression has merely temporarily interrupted the normal growth,

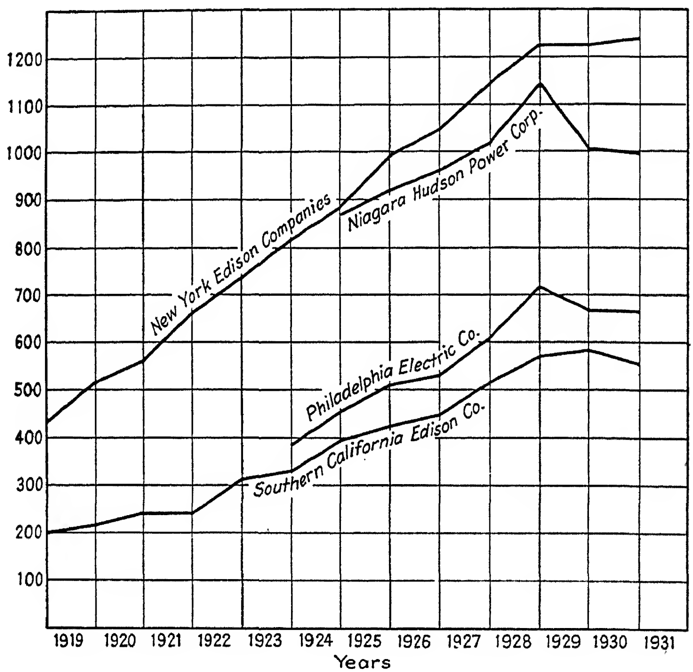


FIG. 5. Growth in peak load of several large power systems.

and that this growth will be resumed after the passing of the depression.

Even during the depression, connected or potential load has been increasing. In other words, a latent demand is being built up, and it is entirely possible that for a few years the rate of growth after the depression may be at an accelerated rate. Throughout the life of the industry, there has been no depression of such magnitude, and hence there is no precedent for guidance. In the relatively mild depression of 1921–22, many of the systems suffered some recession in load, but thereafter the pick-

up was accelerated until about the usual rate of increase was reached.

In any attempt to plot curves such as those in Figs. 5 and 6, it is necessary that the figures of peak load for past years should be for the company as now constituted. In other words, where there have been acquisitions, these should be included as a part of the load for all years covered by the curves.

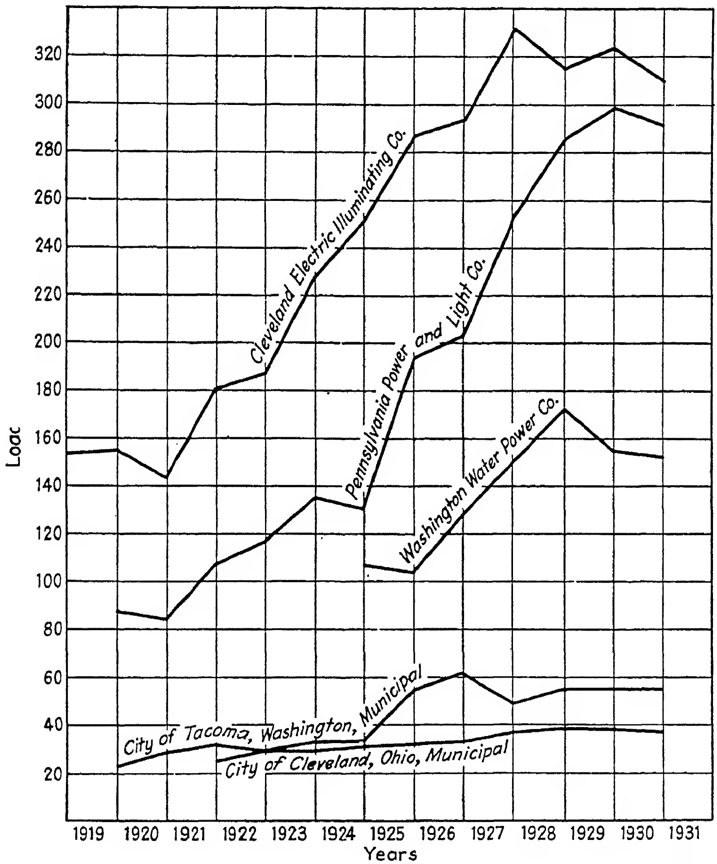


FIG. 6. Growth in peak load of several medium sized power systems.

19. Study of Load Data for Peak Prediction May Be Confined to One or Two Months. — In order to predict the peak load for purposes of determining power plant construction schedules, the study may be confined to those months in which the annual peak loads of the system occur. For many of the power

systems in the United States, the annual peak loads occur either in November or December, and in many systems they occur always in December. Consequently, in many cases, for this purpose the study of peak load, past, present and future, may be confined to one or both of these months. The peak load to be considered should always be the peak load on the generating stations.

20. Simplest Method of Predicting System Peaks. — The simplest method of predicting system peak loads is to gather and plot all the annual peak loads for previous years, care being taken to see that peak loads gathered for the past serve the same territory as the annual peak of the present time. For instance, company *A* may during the past ten years have absorbed companies *B* and *C*. If the peak loads of company *A* for the past ten years are plotted, a very false impression will be given of the rate of growth in peak load, and any conclusions as to additional capacity required in future years based on such a graph would be bound to be very misleading.

What should be done is to take the territory now served by company *A* and go back over the records year by year, making sure that the peak load utilized includes that of all plants since absorbed into the system (with the proper diversity factors applied). The annual system peak loads having been plotted in this manner, preferably on semi-logarithmic paper, the trend is observed and the curve projected several years into the future. The curve is bent either upwards or downwards from what a mathematical extrapolation would give in accordance with any pertinent facts relating to prospective new consumers and in accordance with judgment as to the growth in population and wealth of the territory. The method is not very scientific, but if each year the predictions for the near future are revised in the light of the last year's results, it sometimes gives fairly satisfactory results.

21. Desirability of Making Estimates by Districts. — Many companies have found it very desirable to make all their estimates for load growth by districts. The districts usually correspond with substations, so that the results of the studies may be used also in planning for the necessary capital expenditures for transmission, distribution and substation equipment.

The estimates for the individual districts are assembled into a whole by the application of proper diversity factors, and the

system load and load on the various generating stations is thus determined. In this way also the necessary capacity of the bus lines tying together the various generating stations may be determined and planned for any given year of the near future.

22. Influence of Population on Load Growth. — In any scientific analysis of trends in load growth, population is the first basic factor to start with, for manifestly a territory which shows a rapid growth in population will have a more rapid growth in load than the same district if the population were to remain stationary. Population curves for all territories are quite similar in form. In the early years of growth, the curve is quite flat and then gradually steepens up until it becomes very nearly a straight line with some jogs due to variation from prosperity to depression; finally the curve flattens out and becomes asymptotic as, for instance, the curve for Manhattan Island.

Figure 7 gives the population curve for St. Louis County, Mo. This territory does not include the city of St. Louis, but is a rapidly growing suburban territory tributary to the city of the same name. Saturation is still many years away, and consequently the trend for many years to come will be on the straight line portion of the curve.

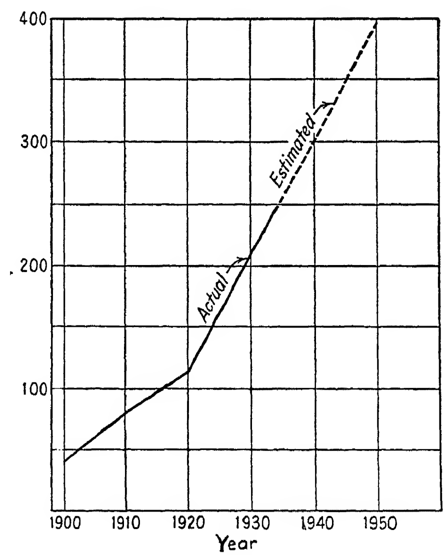


FIG. 7. Population curve for St. Louis County, Mo. (a suburban territory tributary to the City of St. Louis, Mo.).

23. Division of Load into Various Classes. — Experience has shown that more accurate estimates are possible if the load for each district is divided into the various classes of service for which power companies usually keep their statistics, such as domestic service, commercial lighting, street lighting, railways and railroads, commercial power and other utilities.

24. Prediction of Domestic and Commercial Lighting Loads. — The domestic service load is of material importance and should usually be separately analyzed. By placing test demand and energy meters on certain circuits at substations, and also utilizing the readily available data on domestic sales, it is feasible, with a relatively small amount of experimental work, to determine a factor which may be applied to the energy sales for the peak load month in order to obtain the peak load due to this class of service.

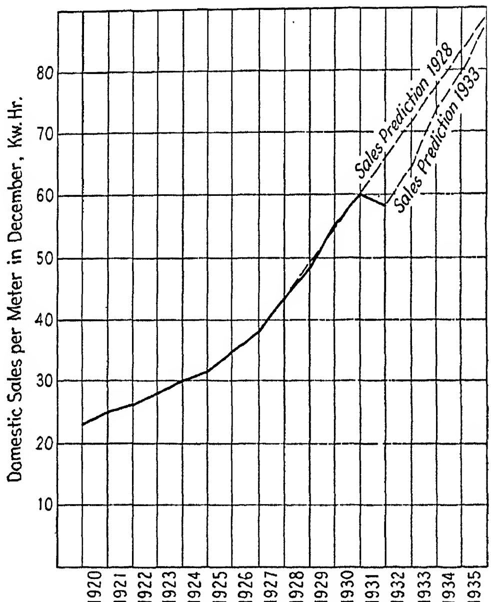


FIG. 8. Domestic sales per meter, peak load month of December, for a typical power company serving industrialized territory with average annual revenue per kwhr 6.4 cents for domestic sales in 1932.

Figure 8 shows actual and predicted domestic sales per meter during the peak load month of December for a typical power company serving an industrialized territory and having an average annual revenue for domestic sales of 6.4 cents per kwhr. For projecting the curve, studies are made by districts considering in each case the expected growth in the use of appliances.

To determine total domestic sales for the peak load month, the number of persons per domestic meter is first determined from company records and the trend for the future is determined by extrapolating the curve. Thus, such a plotting may show

that the number of persons per domestic meter has been gradually decreasing, so that while at present it is 4.0 persons per meter, it may be expected to decline to 3.7 persons per meter five years hence. The next step is, using the population curve for the district, to divide the population for the year of the future under consideration by the number of persons per meter anticipated for that year. The quotient is the number of meters on domestic service which may be expected for that year. Multiplying this by the sales figure for the same year obtained from the sales per meter curve gives the total estimated domestic sales for the district for the month of December of that year.

The process is repeated for the various districts, and the district figures are added together to give the total domestic sales of the system for that December. These sales figures are then multiplied by an experimentally determined factor to obtain the resulting peak load due to domestic service for that month of December. A similar process may be used for estimating commercial lighting peak load.

25. Predictions of Future Power Loads. — The same general principles apply to the prediction of power loads. Here also greater accuracy will be promoted through making estimates on the basis of districts. The power loads for each district for the various years of the past are plotted and the curve is projected into the future utilizing all pertinent data for this purpose. The methods which it is advisable to use will vary more or less in different situations. In some sections a kilowatt per capita curve is useful; in others it may be quite misleading. The policy of the company and the aggressiveness and intelligence of the power sales organization are important factors.

Thus, one company may adopt a policy of taking large power business on an incremental cost basis, whereas another maintains higher power rates. This portion of the business is highly competitive, and a change in policy may entirely ruin a carefully made estimate. Figure 9 shows the mechanical and electrical power in factories of the United States, and indicates that in recent years practically all the growth in the use of power by factories has been taken by the central stations.

In making the power load estimate by districts, the assistance of the power salesman covering that district should be utilized. He knows all the customers and can determine better than anybody else the probabilities of the various customers' increasing

their loads in the near future. Factories are not conceived or built in a day, and the power salesman will know of any proposed new factories to be located in his district and also their probable loads.

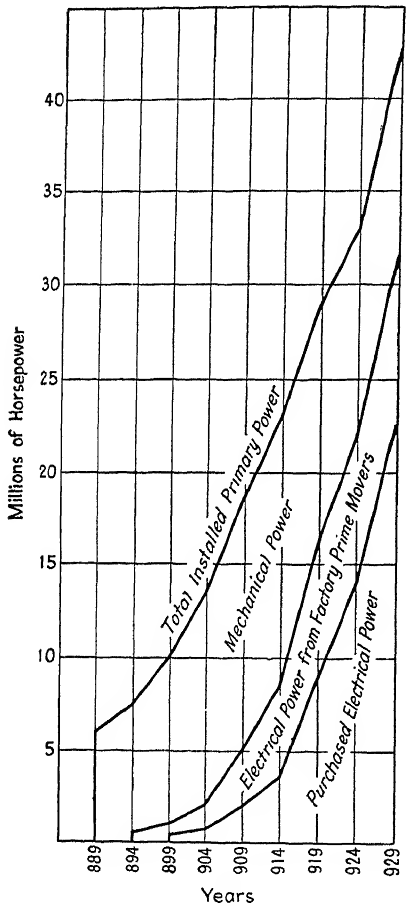


FIG. 9. Mechanical and electrical power in factories of the United States. (Data from U. S. Bureau of Census, Dept. of Commerce).

From company records the connected load (transformer capacity of power customers) is known for the various years, and, with the help of the power salesman, it is possibie to project the sales for the December month several years into the future for the district. The December power sales estimated from any given year for the various districts are then added together and the total is multiplied by an experimental factor to give the December peak power load.

26. Predicting Loads from Other Classes of Service.—The load from railways and railroads is not particularly difficult to forecast several years in the future. Plotting the load for previous years gives a good indication of trend for the next few years, which in the case of electric railways is quite frequently downward, and any large change such as the abandonment of an interurban trolley line or the electrification of a steam railroad is usually known quite long in advance and the effect on load may be quite accurately determined.

The extrapolation of trend curves for street lighting is a relatively simple matter and requires no special discussion.

Similarly, power sold to other public utilities is the subject of definite contracts, and the effect on the company's peak can usually be readily determined. Changes from the peak load experienced from this source can usually be estimated well in advance, so far as this affects the load which the company is required to serve.

27. System Peak Determined from Peaks of Different Classes of Service. — Having determined the peak load of various classes

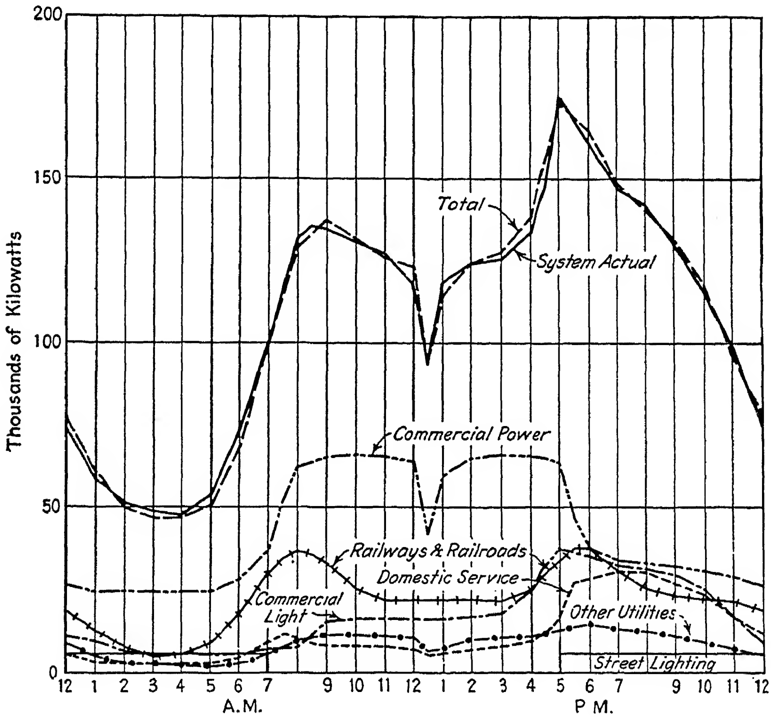


FIG. 10. Load curve for peak December day 1930, showing also component load curves for the various classes of service.

of service as domestic, commercial power, railways and railroads, commercial lighting, street lighting, etc., it remains merely to combine these in order to determine the system peak load for the December month of each year predicted. The peaks for the various classes of service are fortunately never coincident in time and hence straight addition will not give the system peak. In Fig. 10 is shown a load curve for a peak December day. Be-

sides the system load curve, there is also given the load curve for the various individual classes of services.

If the peak loads of each of the various classes of service in Fig. 10 are added up, it gives a total of 196,000 kw, but the actual system peak is only 174,000 kw. Hence the diversity factor is 196,000/174,000 = 1.126. Accordingly, after checking the diversity factor for other peak load days of other years, to obtain the predicted system peak load for each year covered by the estimate, the predicted peaks of each class of service are added and the sum divided by the diversity factor determined as above.

28. Predicted Peak Loads for Future Years. — As previously mentioned, it is desirable to assemble the data by districts as well as for the entire system. Methods of prediction will advisedly vary for different territories and conditions, but the

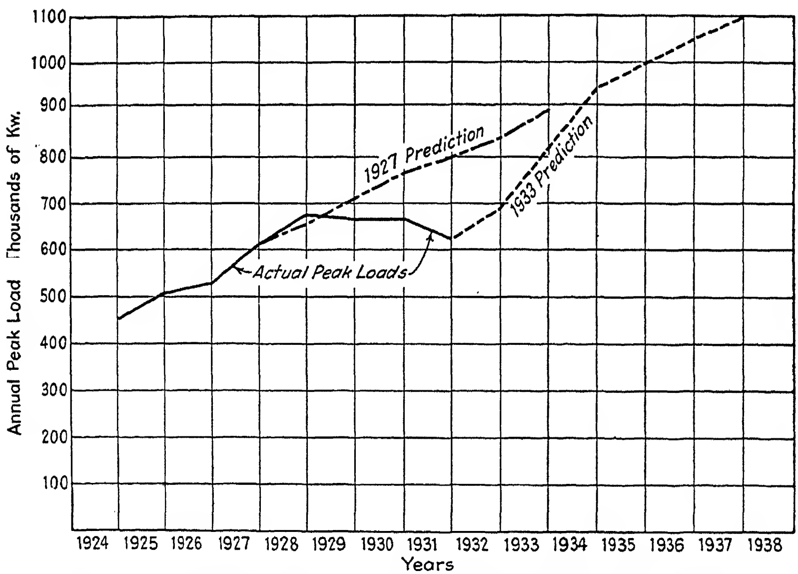


FIG. 11. Prediction of annual peak loads for large power system.

essential procedure for promoting accuracy is to have a built-up estimate starting with classes of services and districts and winding up with the predicted system peak. In every field of estimating, it is true that an estimate which is broken down into its constituent parts and then built up block by block, utilizing all pertinent data in each case, is a much more satisfactory and accurate estimate than one arrived at by overall extrapolation.

Figure 11 shows actual peak loads for a series of years and predictions of peak loads made in 1927 and 1933 for a large power system. The curves show a very wide discrepancy between the predicted peak loads and the actual. This is, of course, due to the unprecedented depression which started in 1929. Heretofore peak load trend curves have shown no material recessions.

From Fig. 11, some may draw the conclusion that when discrepancies between actual and predicted loads may be as wide as the maximum of 21 per cent here shown, there is no use in wasting much time in making predictions. Such a conclusion, however, would be unjustified; first, because a discrepancy as great as this is not apt ever to occur again, and second, because a prediction gives some logical basis for proceeding with plans for the future. A justifiable conclusion would be that predictions of future peak loads should be revised at frequent intervals in the light of the latest available data. By constantly revising such predictions, the curves will reflect current business conditions, and discrepancies will be limited.

29. Required Reserve Capacity. — One factor which has a material effect on the amount of reserve capacity required is the necessary reliability of service. At the lower end of the scale is the tiny plant without any reserve capacity, which still furnishes the electric lights in some remote villages. If the generator breaks down, the folks simply get out their oil lamps which are kept always on hand, and that is all there is to it, except that they grumble a little if they think that they are paying for the "juice" while the generator was broken down. At the other end of the scale is a metropolitan system like the New York Edison. The disastrous and demoralizing effects of a total interruption in service in such a system at, say, 5 P.M. of a December evening, cutting off elevators, lights, subways and all motor services, are hard to visualize.

Another factor which affects the amount of reserve capacity required is the relation of the power received over transmission lines to the peak load. Thus, if a company serving a city obtained a portion of its power over a single transmission line amounting to, say, 100,000 kw, then its reserve requirements should probably not be less than 100,000 kw, regardless of what the other requirements of the situation might be. On the other hand, if the same 100,000 kw could be routed over another transmission line to the same load center, then the fact that 100,000

kw of the company's power supply was received over transmission lines might have no influence on the amount of reserve capacity required. (See also Chapter IV, Section 61.)

Territorial interconnection and interconnection between power plants of a single system influence reserve requirements, and, other things being equal, the more thorough the interconnection the lower the reserve requirements will be. (See also Chapter XIII, Section 183.)

The size of units in the system influences the amount of reserve capacity necessary, as usually the amount of reserve capacity at times of peak load should not be less than the capacity of the largest unit. In systems having very high load factors the schedule for overhauling generating units may become an important factor in the determination of the necessary reserve capacity.

For a company where plants are thoroughly interconnected and which is also interconnected with neighboring power companies, and where reliability of service is of great importance, reserve capacity equal to 10 per cent of next year's estimated peak load is sometimes a sufficient minimum requirement provided that this 10 per cent is greater than the capacity of the largest unit in the system. For another company where reliability of service is of equal importance, but which does not have the advantage of thorough interconnection with other companies, a 30 per cent reserve capacity may be considered necessary. Reserve criteria of most companies are between these two figures, but owing to size of units and the execution of construction programs, actual reserve capacity available often exceeds the criterion established.

30. Utilization of Load Prediction Curves. — Load prediction curves for the various districts of the system should be utilized in planning the capital expenditures for several years in the future for substation extensions, distribution services, tie lines and transmission facilities. These curves, combined in a manner required by the particular conditions existing in each particular system, should also be used to determine the allocation of the additional installation of generating units among the various power plants of this system or to help in determining the location of a new plant.

The load prediction curve for the complete system should be utilized in planning the plant construction schedule for installing

additional generating capacity to meet the load requirements of the near future. To the peak load predicted for any given year should be added the required reserve capacity in order to determine the total capacity which the system should have available in that year. (See Section 29, also Chapter IV, Section 61.)

31. Unwise to Plan Too Far Ahead. — It is unwise to plan such capital expenditures for additional capacity too far ahead. For instance, the executives and engineers of the power company whose load prediction curve is given in Fig. 11 might have decided in 1928 that because of the rapid increase in load they had better build a new power plant and that, in order to secure the lowest per kilowatt costs for capacity and also low production costs, they had better utilize large units and build the plant of sufficient size so that with existing installation the load of five years later could be carried with the proper margin of reserve capacity.

The peak load of 1928 was 610,000 kw, and the peak load estimated for 1933 was 840,000 kw. Assuming 10 per cent required for additional reserve capacity would give a desired capacity of the new plant of 250,000 kw. This capacity, in order to secure the lowest practicable capital and production cost, might have been installed in two steam units of equal capacity. With land and some expenditure for future additions, the plant might have cost $27,500,000 or $110 per kw. Events proved that not more than 70,000 kw of this capacity was actually required even at the end of the period, and the fixed charges on unused capacity might readily have amounted to $2,400,000 per year for the five year period, certainly enough to make a sizable hole in the net available for common stock of almost any company.

Although there were many power companies which solved their apparent requirements for additional capacity in the above manner, the management of the company in question decided that if the predicted peak loads were correct, the fixed charges on unused capacity would more than eat up the operating savings, owing to the great size of the proposed units, and that, all things considered, it would be wiser to install the needed capacity in smaller increments, keeping the installed capacity only about one year ahead of the load.

What the company actually did was to increase its capacity during the five year period by only 100,000 kw. In 1928, they

added one 50,000 kw unit in one old steam plant, and another 25,000 kw unit in another, both of these on a low incremental cost basis. In 1929 they superimposed a 25,000 kw high pressure unit on an old steam plant, thus, in addition to the capacity gain, obtaining a material reduction in unit production cost and in effect rejuvenating the old steam plant and making it one of the most efficient in the system. After 1929 no further plant additions were made during the period, as a decrease in load made such increases unnecessary. The total actual amount paid for additional fixed charges over the five year period on new capacity was $4,050,000, as contrasted with $14,840,000,[1] which would have been the fixed charges over the same period if the 250,000 kw plant proposed in 1929 had been constructed.

32. Advantages of Flexible Program. — The above case illustrates the advantage of utilizing load predictions for the adoption of a flexible construction program, so that, as nearly as may be, the increments of capacity added will be only enough to take care of about one year's growth and so that any change in the situation requiring a revision in load predictions can also be met with a prompt corresponding change in the construction schedule. Even though a higher production cost is necessitated by this procedure, this factor is usually much more than offset by the saving in fixed charges. Furthermore, if sufficient study is given to the situation, it is usually feasible to make just as great reductions in total production cost if the flexible construction program here advocated is followed. This may be accomplished by the rejuvenation of old steam plants, by superimposing high pressure or mercury turbines on existing steam plants and by obtaining the most economical balance between steam and hydro capacity.

[1] 27,500,000 × (fixed charges) 0.135 × 4 (years).

CHAPTER III

FUELS FOR STEAM POWER PRODUCTION

33. Kinds of Fuel. — There are three fuels of major importance in use in the production of steam power in the United States. A number of other fuels, peculiar to the location in which they are produced, but of less importance, are also burned. The fuels upon which the production of steam power depends are bituminous coal, fuel oil and natural gas. Statistical data are not available as to the relative consumption of each in this service. However, the electric light and power companies, chiefly because fuel is the largest and most important consumable item of their expenses, report reliable data on the quantities of fuel used in the production of steam for conversion into electricity. These data for coal, oil and gas for a period of several years are given in Table 3. It is reasonable to assume that the same relationship exists in all other industries where fuel is used for steam making, with a possibly greater proportional use of coal because most of the industrial development is concentrated in areas nearest the coal fields.

TABLE 3

RELATIVE PROPORTION OF FUELS USED BY LIGHT AND POWER INDUSTRY IN UNITED STATES IN PRODUCTION OF ELECTRICITY

Year	Coal or Coal Equivalent, Tons of 2000 lb	Coal, Per Cent of Total	Fuel Oil, Per Cent of Total	Natural Gas, Per Cent of Total
1917	23,802,273	90.3	6.80	2.90
1922	30,130,865	86.7	10.36	2.94
1927	42,230,630	88.9	4.46	6.64
1928	42,745,322	88.0	4.22	7.78
1929	48,858,000	84.9	5.25	9.85
1930	47,248,000	84.1	4.92	10.98
1931	43,788,336	81.4	4.87	13.73
1932	34,330,000	83.2	3.25	13.55

34. Bituminous Coal. — In the making of steam power all grades of bituminous coal are used, ranging from the high rank coals of the Eastern Appalachian field containing up to 14,500 Btu per pound to the Texas lignites averaging 7000 Btu per pound. It is the most abundant of all our natural fuels. According to the U. S. Geological Survey, it is found in workable quantities in thirty-one of the states. Table 4 shows the location of coal fields by states and the estimated quantities. In the area east of the Mississippi River the greatest production as well as the best quality are found. The concentration of population and industry, and the high quality of the coal found there, account for the dominant position in the coal industry occupied by the coal fields of this area. The electric light and power industry reports that in 1929, 72 per cent of the total electricity produced by steam was consumed in the area east of the Mississippi River and that 87 per cent of all the coal used for producing electricity was used by plants in this area.

Less than 1 per cent of the deposits shown by Table 4 have been mined, the greatest depletion having taken place in the Illinois and Appalachian fields, although neither region is even remotely approaching exhaustion. The steam plant manager, having selected coal as the fuel for his plant, can always be assured of a fuel supply for a period far beyond the life of the equipment selected to burn it. This may not always be a major factor leading to a decision in the selection of fuels, but it is one worthy of consideration.

35. Fuel Oil. — Fuel oil is a product of the oil refinery. It has been defined as a residual product in the manufacture of gasoline from crude oil for which no other use can be found. Until 1914 it was a by-product of refining methods unable to turn it into more valuable products. In the distillation process used up to that time, under increasing temperatures, naphtha, gasoline, kerosene, distillate and gas oil were distilled off in sequence, the residue being the fuel oil of commerce. But the ever increasing demand on the refiners for more gasoline led to the development of the cracking process which makes it possible to turn 60 per cent or more of the crude into gasoline. In 1914 the gasoline recovery was 18 per cent of the crude oil processed. In 1929 the average recovery was 39 per cent. This percentage could have been greater had there been more demand for gasoline. The effect of this greater gasoline recovery has been to decrease

TABLE 4*

ESTIMATED TONNAGE OF ORIGINAL COAL DEPOSITS IN UNITED STATES AT END OF 1927

(In millions of net tons of 2000 lb each)

State	Lignite	Sub-bituminous Coal	Bituminous Coal	Semi-bituminous Coal	Semi-anthracite and Anthracite
Alabama	.....	.....	67,583	.....	.....
Arkansas	90	.....	170	1,226	400
Arizona	.....	1,141	10	.....	.....
California	.....	16	27	.....	.....
Colorado	.....	104,175	213,071	.....	100
Georgia	.....	.....	.....	933	.....
Idaho	.....	100	600	.....	.....
Illinois	.....	.....	201,400	.....	....
Indiana	.....	.....	53,051	.....	.....
Iowa	.....	.....	29,160	.....	.....
Kansas	.....	.....	30,000	.....	.....
Kentucky	.....	.....	123,327	.....	.....
Maryland	.....	.....	1,507	6,536	.....
Michigan	.....	.....	500	.....	.....
Missouri	.....	.....	84,000	.....	.....
Montana	315,474	62,985	2,655	.....	.....
New Mexico	.....	172,906	18,925	.....	.....
North Carolina	.....	.....	200	.....	.....
North Dakota	600,000	.....	.....	.....	.....
Ohio	.....	.....	93,967	.....	.....
Oklahoma	.....	.....	46,951	8,000	.....
Oregon	.....	7,000	3,000	.....	.....
Pennsylvania	.....	.....	102,574	9,574	21,000
South Dakota	1,020	.....	.....	.....	.....
Tennessee	.....	.....	25,665	.....	.....
Texas	23,000	.....	8,000	.....	.....
Utah	.....	5,156	88,184	.....	.....
Virginia	.....	.....	20,749	400	900
Washington	.....	52,542	11,412	.....	23
West Virginia	.....	.....	122,644	29,900	.....
Wyoming	.....	590,160	80,563	.....	.....
Total	939,584	996,081	1,429,895	56,569	22,423

* Figures taken from data published by U. S. Geological Survey.

the quantity of fuel oil available from the crude. Figure 12 illustrates this.

Therefore, the supply of fuel oil is closely linked to the supply of crude and to the demand for gasoline. In periods of over-production of crude oil, the refinery process of cracking is carried only to the point necessary to meet the gasoline demand, leaving fuel oil in excess of normal demands. It is during such periods that steam plant managers using some other fuel are offered a

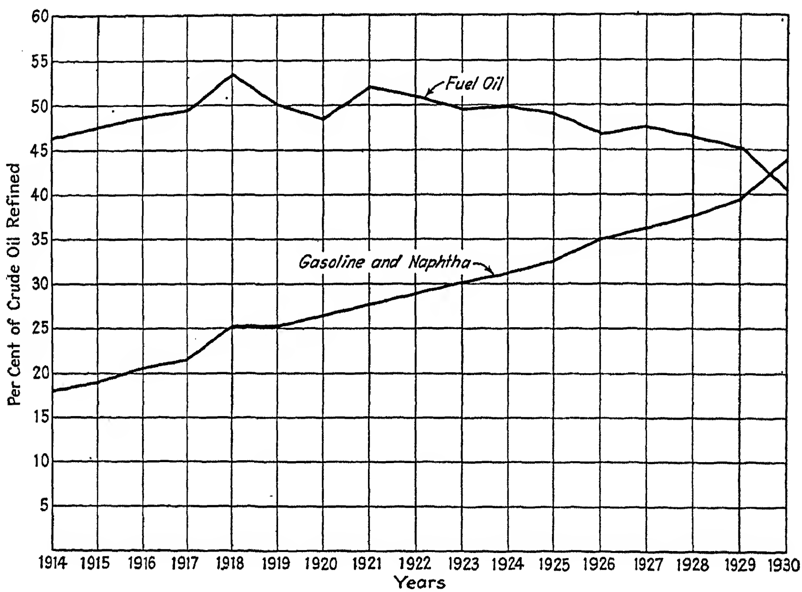


FIG. 12. Production of fuel oil and gasoline in per cent of total crude oil refined in United States from 1914 to 1930, inclusive. (U. S. Bureau of Mines Data.)

supply of fuel oil at extremely low prices on short term contracts. Changing plant equipment to meet these conditions is often profitable. On the other hand, plant designers and plant managers are concerned with equipment having an expected life of 15 to 20 years. To set up a plant to burn fuel oil based on conditions during a flush oil production period, without consideration of an increase in price and without making provisions for future conversion to some other fuel, would be an extremely venturesome enterprise, except under unusual conditions of plant location and fuel supply.

36. Natural Gas. — Natural gas is the third most important natural fuel used in power production although it represents a very small proportion of the total fuels used for that purpose. Table 3 indicates, however, that in the light and power industry it is being consumed in greater quantities than fuel oil. It is the ideal fuel from the standpoint of flexibility of operation and simplicity and low investment cost of equipment used to burn it. It is found principally in the oil producing areas. There it is used as boiler fuel only when an outside market can be found for the fuel oil. Transportation costs, chiefly fixed charges on pipe lines, handicap it in competition with coal from the nearby coal fields in the great industrial centers, where the largest fuel market is found.

TABLE 5*

NATURAL GAS PRODUCTION AND QUANTITY CONSUMED FOR THE PRODUCTION OF ELECTRICITY IN THE LIGHT AND POWER INDUSTRY, 1930

State	Production		Used for Production of Electricity in Public Utility Plants	
	Billion Cubic Feet	Per cent of Total	Billion Cubic Feet	Per cent of Total
Texas	517.9	26.6	43.8	36.4
Oklahoma	348.1	17.9	6.7	5.6
California	334.8	17.2	26.2	21.8
Louisiana	278.3	14.3	18.6	15.4
West Virginia	144.	7.4	0.1	0.1
Pennsylvania	88.	4.6	0.1	0.1
Ohio	63.	3.3	4.3	3.6
Wyoming	43.	2.2	0.2	0.2
Kansas	37.6	1.9	12.6	10.5
Kentucky	28.0	1.4	0.0	0.0
Arkansas	18.6	1.0	1.5	1.2
Others	40.6	2.2	6.2	5.1
Total	1,943.4	100.0	120.3	100.0

* Developed from data published by U. S. Bureau of Mines, Department of Commerce.

The true market of natural gas is not under boilers for steam production, except in areas near the source of production, be-

cause natural gas is, on a long term basis, much more valuable for domestic and industrial heating. The recent great increase in use in boiler plants is explained by the construction of many new and modern pipe lines, made possible by the development of cheaper methods of manufacture and laying of these lines, bringing gas to the great industrial centers before its true market had been properly developed, the gas being sold for use under boilers at dump prices.

Despite this condition most of the gas is consumed near the producing areas. By referring to Table 5 it will be noted that in the year 1930 Texas, Oklahoma, California and Louisiana accounted for 76 per cent of the total gas production and used for steam electric production 79.2 per cent of all the gas used for that purpose. If Kansas, which is very close to the Oklahoma field, be included, the consumption for the five states for steam electric production becomes 89.7 per cent of all gas used for that purpose.

The future of natural gas as a fuel for the production of steam power is problematical. It always will be an important factor in areas near producing centers. But in the great industrial areas, near adequate coal supplies, when the true market is fully developed, it appears reasonable to assume that it will be of very little importance in the production of steam.

37. Other Fuels. — A number of other fuels are used in the production of steam power. These fuels are mostly limited in quantity, are by-products resulting from processing other fuels and materials and are of local importance only. First among these in value and use is anthracite in the steam sizes. Others are petroleum coke and coke breeze, refinery sludge and wastes, coke breeze from by-product oven coke, tar, blast furnace gas and wood wastes. With the exception of the steam size anthracite these fuels are chiefly used at the place of production. Where available they present a special problem to the designers and operators of power plants. It is proper to value them in terms of the replacement price of the lowest cost fuel competing with them in the particular market where the plant is located.

Anthracite. — In the preparation of anthracite for the domestic heating market approximately 25 per cent of the tonnage is unavoidably broken into pieces too small to be suitable for that purpose, this percentage varying somewhat with production practices and the seams from which the coal is mined. This

small coal is reclaimed and used by the mines or sold in nearby markets for the production of steam. It is classified according to the following A.S.M.E. schedule for steam sizes:

	Round Mesh Screen Diameter of Hole in Inches	
	Passes Through	Passes Over
Buckwheat No. 1	9/16	5/16
Rice (Buckwheat No. 2)	5/16	3/16
Barley (Buckwheat No. 3)	3/16	3/32
Undersize or Culm	3/32	....

Recent developments in small stoker design for domestic heating have practically eliminated the No. 1 Buckwheat size as a steam fuel.

The proximity of the Pennsylvania anthracite fields to the eastern industrial centers of New England, New York, New Jersey and Pennsylvania has given this fuel a wide use in this area. Where smoke ordinances are enforced it is in demand as a smokeless fuel.

Declining production of anthracite for domestic consumption and better recovery methods in preparation are limiting the supply of this fuel. It is usually sold as a by-product below the cost of production, and its greatest handicap in competition with other fuels is the cost of transportation. It has a low Btu content and is difficult to burn with efficiencies comparable to those obtained from other fuels. This limits its use to the areas mentioned. Total production of steam sizes of anthracite in 1919 was 31,200,000 short tons, and in 1929, 25,900,000 short tons.

River Anthracite. — Another supply of small size anthracite is known as river anthracite. It is found in the beds and along the banks of the streams tributary to the anthracite fields. This coal originated at the mines and was discarded either voluntarily or involuntarily by the operators. It is reclaimed by dredges, washed and sold locally, most of it finding its way into steam power generation. The average annual production is about 750,000 tons. The supply of this fuel is diminishing as the old

and cheaply worked beds are used up and as refinement in colliery practice permits retaining and using the fine coal once allowed to escape.

By-product Fuels. — Petroleum coke and coke breeze, refinery sludge and wastes are, as their names imply, oil refinery by-products. Their production depends on refinery practices and the demand for the finished products of the refinery. They have a very limited and local use.

Coke breeze, tar, blast furnace gas and wood wastes are industrial by-products of considerable fuel value but having very limited demand and only local use.

38. Use and Price Trends of Fuels. — The fuel situation presents a very confused picture to the power plant manager. Improvements in fuel technology and fuel burning equipment make it possible at all times to substitute one fuel for another, provided it is economically sound to do so. He is therefore compelled to consider not only the technical aspects of fuel performance but also fuel prices and price trends.

Coal. — The coal industry, stimulated by demand during the World War and the consequent high prices, is greatly overexpanded. Annual consumption reached a peak of 624,000,000 short tons in 1917 and has been declining ever since. This declining consumption has been brought about by the substitution of other fuels and by increasing efficiency in its utilization. In the light and power industry, coal per kilowatt-hour generated has decreased from 3.20 lb in 1919 to 1.51 lb in 1931. Railroads and other heavy coal consuming industries have made similar economies in use. Likewise prices have been declining. The following table from U. S. Department of Commerce data shows the price trend.

Composite Wholesale Price* of Mine Run Bituminous Coal per Short Ton of 2000 Lb.

Year.	1923	1924	1925	1926	1927	1928	1929	1930	1931
Price.	$4.83	4.21	4.12	4.31	4.26	4.03	3.95	3.91	3.74

* These are wholesale prices at central markets.

Declining production and declining prices have put the coal business on a profitless basis. The larger producers who have modernized their preparation equipment and mechanized their

mines are said to be able to make a profit on 1931 prices. No great increases in consumption are to be expected, owing to increasing motorization and electrification of transport, to increasing electrification of industry and to the increasing competition from other fuels for use in the production of power.

Oil. — Fuel oil prices should be considered only on a short term basis. The supply is too intimately tied up with crude oil supply and gasoline demand, as it is always a potential source of gasoline. With the hydrogenation process recently developed, refiners expect to be able to convert all the crude into gasoline. Following is a table prepared from U. S. Department of Commerce data giving fuel oil prices for an eleven year period.

Average Prices* of Fuel Oil per Barrel

Year..	1921	1922	1923	1924	1925	1926	1927	1928	1929	1930	1931
Price..	$1.30	1.24	1.20	1.35	1.46	1.47	1.14	0.913	0.891	0.780	0.565

* These prices are the average for five refinery locations quoted ex-refinery.

For marine use, fuel oil is ideal and is valuable for reasons other than its fuel value. A decrease in crude oil supply or an increase in gasoline demand, or both, will cause fuel oils' present position as a competitor with coal in the power field to recede gradually, as the demands for it in the marine field must first be satisfied.

Natural Gas. — Natural gas, excepting in areas near to centers of production, will have a very limited future use as a boiler fuel. Its major advantages in competition with other fuels are not its price but rather the ease and flexibility of handling it and the low first cost of equipment to burn it. Its use may be worth while in small situations, but where coal is available it may be expected to disappear from the larger plants.

39. Choice of Fuels. — Many steam power plants are restricted in the choice of fuels by location or other considerations beyond control. An extreme example is a plant located in the anthracite fields or in oil fields where the other fuels are unable to compete. But where plants are so located that several fuels are available or new fuels appear to compete with those in use, the management must determine which fuel is the most economical. The cost of the fuel per unit of heat is only one of many factors that must be considered in making this decision.

Actual performance of the fuel on the grate or in the furnace

and the influence on the design and cost of the equipment to convert the heat of the fuel into steam are the only true measures of the value of a fuel. This is particularly true of coals. All bituminous coals can be burned in pulverized form but not at the same efficiencies, and not with the same cost of equipment and of operating. The kind of coal determines the type of stoker required: anthracite requires a chain grate; some bituminous coals give best results on underfeed grates, others on chain grates.

A steam plant designed to produce a given result with a certain fuel or fuels may cost almost any conceivable amount, depending on conditions and the judgment and ability of the designer, so that the designs and estimates used may not be the most economical for the fuel finally selected, but if reasonably correct and on a comparable basis, the comparative values of the fuels obtained will determine the best fuel for the plant.

It is therefore necessary to make an analysis of the cost of making steam under assumed conditions with the several fuels under consideration, comparing the value of the fuels in terms of their influence not only on overall boiler plant performance but also on plant equipment.

The first step is to determine the efficiency of the equipment in utilizing the heat of the fuel in making steam.

Although, in the consideration of the fuel to be burned in a proposed plant, tests to determine performance made in an existing plant are not necessarily indicative of the results which may be obtained in the proposed plant, and even in old plants changes in equipment for testing a proposed new fuel may not be warranted, yet it is possible to estimate the efficiency at which a boiler plant will operate provided the character of the fuel and its influence on the various performance factors are known. It is considered outside the scope of this work to detail the principles of combustion required to make such calculations, but it may be in order to state that all fuels cannot be burned with equal efficiency on the same equipment. For instance, anthracite burned in pulverized form will have more combustible in the flue gas than Pittsburgh bituminous, thus showing a greater loss at that point. Gas and oil can be burned with less excess air than coal with a consequent lower loss of heat in the flue gases. On the other hand, gas and oil, with greater hydrocarbon content, will show a higher latent heat loss than coal.

With all such items properly considered, comparable estimates of efficiencies with various fuels may be made.

In the case of an existing boiler plant, the efficiency of a proposed fuel may be calculated from known performance data on fuel in use. When actual is compared to calculated efficiency, care must be taken to correct the calculated data by a factor to cover inability to achieve calculated performance in operation.

Figure 13 illustrates graphically the calculated relative performance of several fuels if burned under the same boiler, the

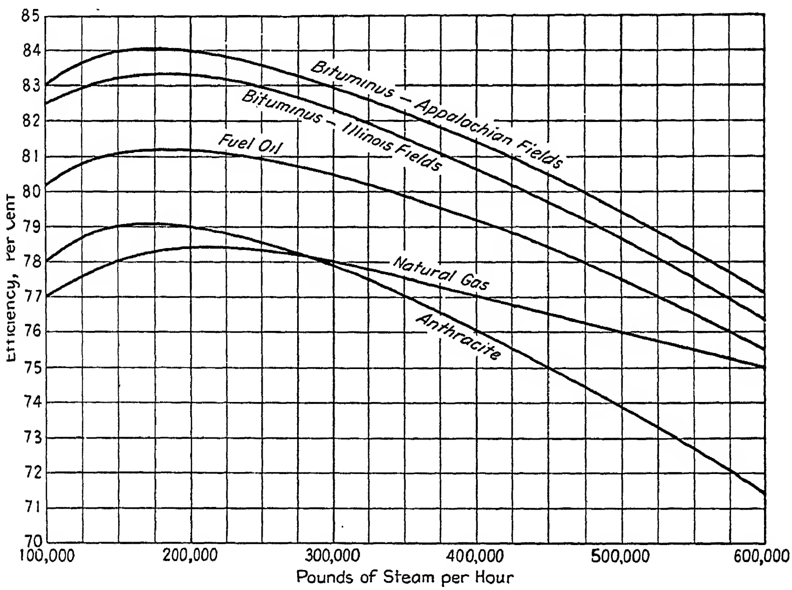


FIG. 13. Comparative boiler efficiencies to be expected with various fuels.

only difference being in the combustion equipment; all coals were assumed to be burned in the pulverized form.

With comparative efficiencies of the fuels under consideration established it is then easy to evaluate them on any convenient basis, such as cost of 1000 lb of steam per million Btu of fuel burned.

The comparison of fuel values is not complete, however, without a further study of the influence each fuel will have on plant operation and capacity in the case of an existing plant and of the influence on plant design, layout and cost in the case of a new plant.

40. Effect of Fuels on Boiler Capacity. — The boiler plant capacity is often very markedly affected by the choice of fuel. As an example, a plant burning anthracite No. 3 buckwheat containing approximately 10,800 Btu per pound and costing $1.94 a net ton was offered a supply of No. 4 buckwheat containing approximately 9000 Btu for a price of $1.10 a net ton. Test showed that this No. 4 coal could be burned on existing equipment at an average boiler efficiency of 56 per cent. The average efficiency with the No. 3 coal was 69 per cent.

The annual fuel cost with the No. 3 coal was.......	$153,000
The estimated fuel cost for the same production of steam with the No. 4 coal was...............	128,000
showing a fuel saving of.....................	$ 25,000

But it was found also by test that, to supply the same steam demand on the plant with the No. 4 coal, additional boiler capacity, costing $200,000, would be required, and that the annual fixed charges required (13.5 per cent of the investment) would entirely wipe out these savings; therefore, it was inadvisable to adopt the cheaper fuel.

41. Effect of Some Coals on Stokers. — Certain coals are much more severe on stoker parts and furnace walls than others. Consequently, operating and maintenance costs for these coals are higher and are a liability against them in comparison with coals not having the same effect. Oil and gas fired boilers can usually be operated with fewer men than those fired with coal, and on boilers using induced draft fans maintenance costs are less because of the absence of cinders and dust in the flue gases.

42. Effect of Low Btu Coals on Handling and Storage Equipment. — Operation and maintenance costs on fuel handling, preparation and storage equipment will vary almost directly with the tonnage handled. It is obvious that low Btu coals place a greater burden on this equipment than the high grade coals. In the example cited above with anthracite coals, the plant equipment now handling 79,000 tons of No. 3 coal annually would have been required to handle 117,000 tons of the No. 4 coal. Maintenance and operation of oil storage plants are comparatively simple and this item almost entirely disappears for gas fired plants.

43. Effect of Fuels on Investment. — As demonstrated in the preceding examples some fuels require more or larger equipment

to produce the same results as others. This is true not only with anthracite but also with the several grades of bituminous and with gas and oil. The resulting increase or decrease in size of buildings and equipment increases or decreases the investment cost.

Since with some coals the tonnage to be stored and handled is greater than with others, and with other fuels the need of storage handling and preparation equipment almost entirely disappears, it is clear that investment in this equipment will vary over a wide range and that the investment charge against steam for this item will also vary.

44. Effect of Fuels on Auxiliary Power Consumption. — With all fuels it is necessary to use some of the power produced in the handling and burning. Draft fans, pulverizers, oil pumps, conveyors, all are power consuming apparatus needed to burn fuels efficiently, and these power requirements will vary considerably with the type of fuel in use. Approximately twice as much power is required to pulverize anthracite coal as Pittsburgh bituminous. Induced draft fan power required for natural gas is approximately 90 per cent of that required for Pittsburgh bituminous. The use of this auxiliary power in producing steam reduces the quantity of free power available for sale or for other uses, and must be considered in any complete comparison of fuel values. This results in a charge against the fuel of the annual fixed charges on that portion of the total investment used for auxiliary power, plus the cost of the power itself.

45. Summary of the Effect of Fuels on Plant Operation and Design. — Summing up, it may be seen that the factors in plant operation and design which are influenced by the fuel and which are reflected in the fuel cost of steam are:

1. Effect on boiler plant capacity, either limiting or increasing.
2. Operation and maintenance cost on fuel burning and heat absorbing apparatus.
3. Operation and maintenance cost on fuel handling, preparation and storage equipment.
4. Annual fixed charges on investment in fuel burning and heat absorbing apparatus.
5. Annual fixed charges on investment in fuel handling preparations and storage equipment.

6. Annual fixed charges on investment in that portion of plant capacity used for auxiliary drive on fuel burning, handling preparation and storage equipment.

46. Comparison between Two Fuels; a Specific Case.—To illustrate the effects of kind of fuel on plant and plant operation, a typical comparative set-up is given below. The difference in plant investment costs represents the influence the two fuels considered have on plant equipment, principally on fans and fuel burning and storage equipment.

Items	Oil	Coal
Cost of fuel	$0.80 per bbl.	$4.20 per 2000 lb
Cost of fuel per million Btu	$0.133	$0.146
Btu as fired	18,500 per lb	14,350 per lb
Net plant maximum capacity, pounds of steam per hour	1,000,000	1,000,000
Average plant efficiency, per cent	81.2	84
Annual capacity use factor, per cent	57	57
Cost of plant	$2,000,000	$2,350,000
Total annual fuel cost for plant net output	792,000	773,600
Annual fuel cost for operating fans for plant net output	14,000	12,000
Annual fuel cost for operating fuel burning equipment	15,000	22,000
Annual maintenance cost on fans and fuel burning equipment	9,000	12,000
All other operating costs	160,000	160,000
Annual fixed charges on plant @ 13.5 per cent	270,000	317,250
Total annual cost for producing steam	$1,260,000	$1,296,850

Although the boiler efficiency with oil is lower and the annual fuel cost is higher, a proper consideration of all the factors involved other than continuity of fuel supply at current prices, shows the use of oil to be the more profitable. This above example is entirely hypothetical and is given to show that choice between fuels depends not only on relative efficiencies and costs but also on the investment and operating costs peculiar to each fuel under consideration.

CHAPTER IV

STEAM POWER PLANTS

47. Importance of Steam Power. — Steam is, by a considerable margin, the most important and most used of all agents for producing mechanical and electrical energy. Figure 3, Chapter II, shows the relative amount of steam power, hydro electric power and oil engine power installed in the central station industry. It will be noted that more than 70 per cent of all central station installations use steam. The relative importance of steam is probably much greater in other industries.

48. Development of Prime Movers. — How to harness steam to convert its energy into useful work was the problem that faced the early experimenters. Savery and Newcomen blazed the path with their designs for a steam engine, but it remained for James Watt to develop the engine which was to revolutionize world industry. The reciprocating steam engine is the most widely used instrument in converting steam into useful work. It is exceeded in total horsepower in use only by the steam turbine. The reaction type of turbine was invented by Parsons and appeared in 1884. The impulse type which extracts the energy in steam on a principle entirely different from that used in the reaction type was invented by De Laval in 1889. The development of this prime mover came at a time when the rapidly growing electrical industry was looking for a new type of engine. It was found that the alternating current generator could be built of larger capacity and more cheaply if a prime mover having a high rotative speed was available. The turbine filled this requirement, and together with the generator, formed an ideal unit for the production of electrical energy on a large scale. Units up to 70,000 hp capacity are not uncommon, and several units of more than 200,000 hp have been built.

49. Application of Steam Power. — The application of steam power through the correct prime mover requires the consideration of the two vital items of operating expense and fixed charges. Included in operating expenses is the cost of fuel, labor, supplies,

repairs and maintenance. The total of these costs varies with the number of hours the equipment is in service. The unvarying items of fixed charges are interest on money invested, allowance for depreciation and obsolescence, insurance and taxes. These costs continue whether the equipment is used or not. Both operating expenses and fixed charges are affected by many factors such as steam pressure and temperature conditions, size, space requirements, kind and reliability of service demanded, type of fuel to be used, and elements of a similar nature.

With all these variable quantities to be considered, the application of steam power has taken many different forms. It is possible to group them, omitting the many variations or subclassifications, into three general classifications:

1. Direct coupling of the prime mover, either engine or turbine, to the apparatus to be driven.
2. Indirect coupling of the prime mover to the apparatus to be driven through line shafting, belts or other mechanical devices.
3. Indirect coupling of the prime mover to the apparatus to be driven through electric motors.

Each particular situation must be analyzed and the many influencing factors evaluated before the best method can be selected.

Direct coupling of the prime mover to the driven apparatus is the most elementary manner in which power can be applied. If the source of steam supply is convenient, obviating the necessity of long pipe runs, if there is a nearby use for the exhaust steam and if the space requirements are not too great, this method will probably give an overall cost lower than the other two. Paper mills and textile mills occasionally use this application to good advantage, but such ideal conditions are seldom to be found.

Every one is familiar with mills and shops in which numerous machines are driven by belts from long line shafts. Imagine the confusion of pipes and equipment if each machine were driven by a steam engine! Either a large steam engine or an electric motor is used to drive the shafting. This method often satisfies the requirements for the most economical application of steam power.

Electric drive has so many advantages, however, that today

industry is about 74 per cent electrified. Of 43,000,000 hp used in industry, approximately 32,000,000 hp is in electric motors. To drive these motors, a supply of electricity is required. This is obtained from one of two sources, either a power plant owned and operated by the industry and located near the place where the electricity is used, or the central station supply of the local light and power company.

50. Similarity between Industrial and Central Station Steam Power Plants. — There is not much difference between the industrial and the central station power plant. In each are installed stokers, coal pulverizers and burners or other combustion apparatus, boilers and some type of prime mover, usually a turbine, connected to an electric generator. The industrial plant, producing electricity on a relatively small scale as compared to the central station, is seldom justified economically except where there is a use for exhaust or low pressure steam for heating and process work. The turbine selected is, therefore, usually a back pressure type, exhausting to the plant low pressure steam mains at pressures slightly above atmospheric, or a bleeder type, from which the steam is extracted at some desired pressure before it arrives at the exhaust end of the turbine.

In the central station, the turbine discharges its exhaust to a condenser. Condensing turbines are seldom found in industrial plants and are economical only where the increment of cost for installing and operating them is lower than the cost of a block of power, of a size equal to the turbine capacity, purchased from the central station. (See Chapter XV for discussion of industrial steam power plants.)

51. Purpose of a Steam Power Plant. — A steam electric power plant is an assembly of fuel burning, heat absorbing, steam producing and steam consuming equipment, brought together to convert the energy in the fuel into useful and usable form. It is man's crude attempt to unlock the storehouse of the sun's heat generated some millions of years ago. To perform this work, the plant designer or assembler has to choose from the many sites, fuels and kinds and types of apparatus offered. The choice is not always easy. The guiding principle should be to produce a plant able to generate electricity in the required quantities with the requisite reliability at a total operating and fixed cost lower than the cost would be with any other combination of apparatus and fuel.

52. Plant Location. — The location of a plant is of prime importance. Three principal factors influence the choice of plant sites, namely, accessibility to the load to be served, adequate water supply and source of fuel supply.

Accessibility of Plant to the Load. — Proximity to the load to be served is important in establishing the location of a steam electric power plant. Investment in transmission structures, and transmission operating costs and operating hazards, decrease the closer the plant is to the load.

Some years ago, when "superpower" was a word newly coined, many engineers visioned mammoth central power stations containing numerous large generating units from which transmission lines radiated to serve a wide area. Time has proved this idea to be erroneous. It has been generally found that any given area is better and more economically served by several plants of moderate size, each plant supplying a localized portion of the load and tied in with the other plants and the system with transmission lines. For this reason, plants are located as near the center of gravity of a portion of the load as possible, but may be found at some distance from the center of the load of an entire area.

Such an arrangement is limited only by the need of an adequate water supply, of easy access to the plant for transmission facilities and of transportation facilities necessary to bring the fuel into the plant. Consideration must also be given to the nature and quality of the community surrounding the site. The nuisance at times created by plant smoke, ashes and noises often prohibits the erection of a plant in a built-up residential section on a site which otherwise might be ideal for the purpose.

In discussing the location outside the city limits of the Trenton Channel plant of the Detroit Edison System, Mr. C. F. Hirshfeld, Chief of the Research Department of the company, said (Trans. A.I.E.E., 1925, page 355):

> "The first two large steam plants of the Company are located within the city boundaries. . . . The territory external to Detroit was thus necessarily supplied by lines radiating from Detroit and fed by the underground system. . . . as the density of load in Detroit and in the surrounding territory increased, it brought about several very illogical, undesirable and costly consequences. The most obvious were:

"Power generated in plants located on costly land within the city and subject to high city taxes was transmitted over costly underground structures also subject to city taxes, for the purpose of supplying overhead transmission lines serving small suburban towns and cities and country areas. . . .

"The power required for service to the least saturated territory had to be passed through the most nearly saturated territory, thus unnaturally increasing the difficulties brought about by congested streets, high property values and the like. . . . The location also has the advantage of placing the plant in a section of the territory which is rapidly developing to a dense industrial district."

Water Supply as Affecting Plant Location. — All large central power stations require great quantities of water for condensing the steam exhausted from the turbines. Even in modern high pressure plants, where turbine steam consumptions are low, the water requirements are tremendous. In a 100,000 kw plant, this amounts to 500 tons, 120,000 gallons, per minute, which is at a rate sufficient for the daily consumption of a city of 1,700,000 inhabitants. These plants must therefore be located on or near large bodies of water, lakes, rivers, etc.

In 1925 a survey was made of the power resources of the State of Pennsylvania.[1] Among the many proposals submitted was one to build large power stations of 500,000 kw capacity, at or near the mines, and transmit the energy made to the load centers instead of hauling the coal. One important argument presented against this proposal was the lack of adequate water supply near the mouth of the mines. When it is realized that only four rivers in Pennsylvania, the Delaware, the Susquehanna, the Allegheny and the Ohio have summer flows in excess of the summer condensing water requirements of stations of this size, it is evident that very few sites exist on which such large plants could be built.

Often, however, load requirements demand a plant where water in sufficient quantities is not available. Perhaps the situation is inland where rivers and lakes do not exist, or perhaps the industrial plant to be served by its own power plant is located away from water owing to economic considerations other than

[1] Report of the Giant Power Survey Board to the General Assembly of the Commonwealth of Pennsylvania, 1925.

power costs. In such cases, where real estate is cheap, cooling ponds or spray ponds are customarily used; where it is expensive, cooling towers which take up considerably less space are installed. There is no physical limit to the size of this kind of installation, but since investment and operating costs are increased, the economic limit is soon reached and such methods are used only in small installations.

Fuel Supply as Affecting Plant Location. — Although the economical selection of fuels is important from the standpoint of design and equipment, seldom does it directly influence the location of a plant. With improved equipment and better knowledge of combustion principles most modern plants are independent of any particular kind of fuel. It is true that there are plants located at the mouths of mines or near oil and gas fields, but it will be found that usually the presence of a nearby load or water supply was the deciding factor in locating the plant.

A combination of all three elements — load, water and fuel — at the same place makes an ideal situation. The mine mouth plant is exemplified by the Springdale plant of West Penn Electric System near Pittsburgh, Pa., on the Allegheny River; the Windsor plant of the Ohio River Power Company on the Ohio River near Wheeling, W. Va., and the Dresser plant of the Public Service Company of Indiana on the Wabash River near Terre Haute and Indianapolis, Ind. In most cases, however, it has proved more economical to haul the energy as coal than to transmit it as electricity.

A plant must be located so that it is accessible either by railway or by waterway for the delivery of fuel, and there must be land at a reasonable cost nearby to provide for the unloading and for storage of a reserve supply. This condition cannot always be met in metropolitan districts, such as New York City or Philadelphia, where land is very expensive, so that for some plants in these areas no storage is provided and the plants must depend on daily shipments.

Location of Industrial Plants a Simpler Problem. — The foregoing applies to a central station. Selecting a site for a power plant for a single industry is much more simple. If, as is usually the case, the plant also supplies heating and process steam, it is obvious that the only consideration is neither water nor fuel supply but the cost of transmission facilities and pipe lines, and

to make these short and less expensive, the plant should be located as close to the point of use as conditions will permit.

53. Loads and Load Curves. — It is necessary, in order to design and operate a power station or a power supply system properly, to know or to be able to predict the magnitude and character of the service required. This knowledge is obtained from the "load curve" on which the plant or system operates. It is a graph on which the magnitude of the loads in kilowatts for any time interval is used for ordinates, and the time intervals as abscissae. The time interval may be of any duration, beginning with the instantaneous value of the load. The integrated area under the curve represents the time-load value for the use of the load, and is expressed as kilowatt-hours. For this reason, the time interval usually selected is the hour and the curve is made daily.

Each class of service supplied produces its own characteristic load curve and no two are ever identical. They are similar in that peaks representing periods of high load and valleys representing periods of low load occur, but the time of these occurrences varies. A lighting load, for instance, produces a sharp peak in the evening hours immediately after dark and a long low valley for the remainder of the time. An industrial power load will produce a long plateau shaped peak during the working hours and later almost disappear. A traction load gives sharp morning and evening peaks with a valley between. For a plant used for a public supply, the load curve is the composite of all the load curves supplied. The load curve of an industrial plant likewise reflects the characteristics of various departmental activities and is a composite of all the departmental loads.

If the load served by a public utility is chiefly for lighting and for domestic service, the combined load curve partakes of the nature of that particular class of service. This is illustrated by the load curve in Fig. 14 where the service in a small community is 75 per cent for lighting and other household use. Conversely, the load curve shown in Fig. 15 is supplied in an area where the service is 80 per cent for power use. Note the difference in the shape of the two curves. Seasonal influences also affect the shape of the curve. In a large metropolitan system, serving all classes of load, in the winter months the early lighting load overlaps the power and traction load, so that the peaks occur in the evening. In the summer months this overlapping does not

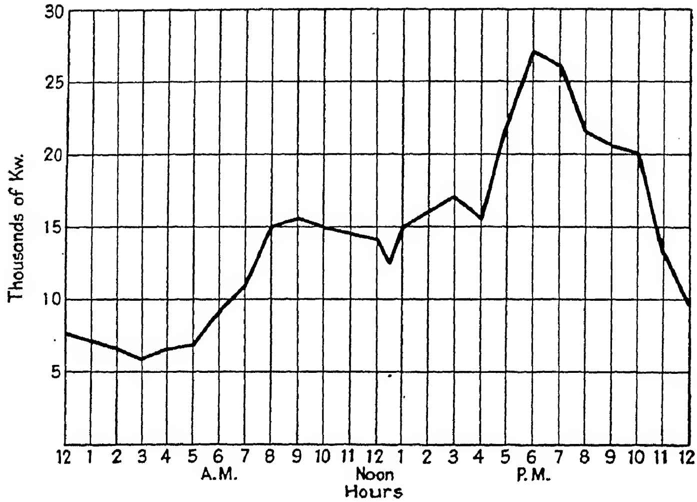


FIG. 14. December peak day load curve of a power system in which domestic and lighting use of electricity is predominating.

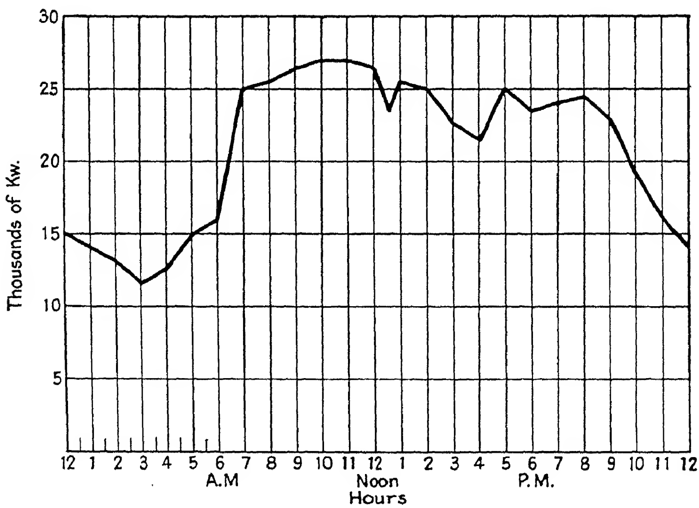


FIG. 15. December peak day load curve of a power system supplying chiefly industrial users.

occur, and the peaks are determined by the traction and power loads and occur in the morning. Figure 16 is the maximum winter load curve of such a metropolitan system, and Fig. 17 is the summer load curve of the same system.

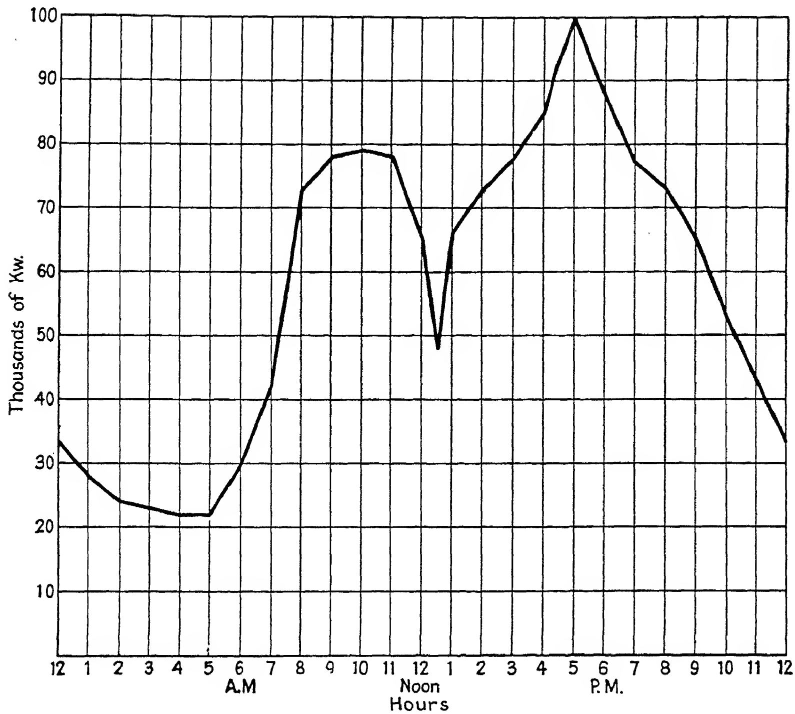


FIG. 16. Typical December peak day load curve of a metropolitan system load.

The daily load curve is the most useful form for showing load characteristics, and it is the basic curve for all operating and engineering analyses.

54. The Load Duration Curve. — In economic studies for periods of a week or longer, the load duration curve developed from the daily load curves is convenient and often used. A typical curve of this description is shown in Chapter XII, Fig. 43. As illustrated, it represents the cumulative duration of all loads in a power system. Each point on the curve indicates that, for the corresponding number of hours on the abscissa, the load has been equal to or greater than the corresponding load on the ordi-

nate. The area under the curve represents the total kilowatt-hours supplied for the period covered.

In preparing this curve from the daily load curves, the loads for each hour are tabulated according to magnitude. These loads are then plotted as ordinates in decreasing order of magni-

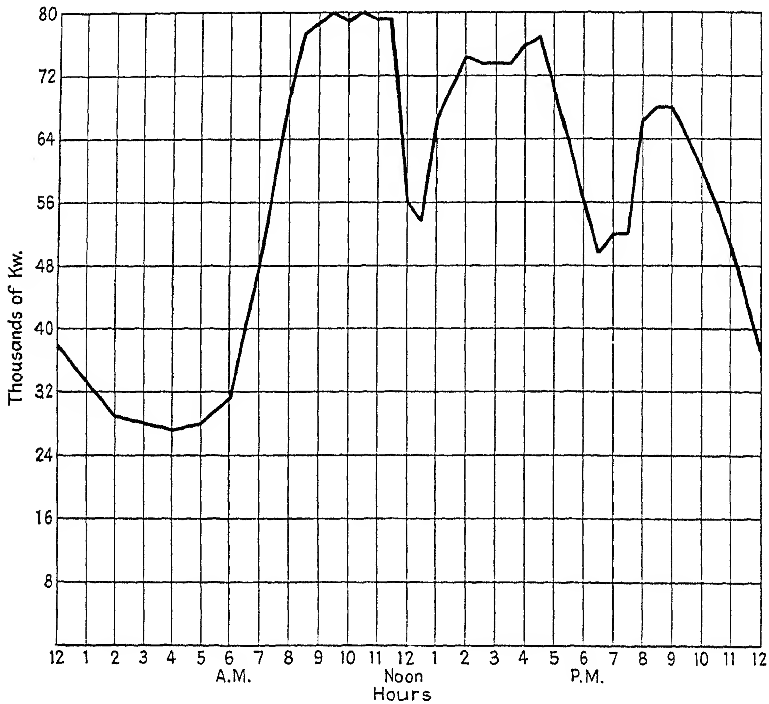


FIG. 17. Typical August peak day load curve of a metropolitan system load.

tude with cumulative time as abscissae. Instead of plotting actual loads it is often convenient to use as ordinates the ratio of the loads to the maximum load. It should be noted that an annual load duration curve neglects the time and seasonal influence, as all loads, regardless of hour or day or month of occurrence, if they are of the same magnitude, are plotted as one point on the curve. For careful studies, therefore, curves of this type are best plotted on a weekly or a monthly basis.

55. Diversity Factor. — The coincidence or non-coincidence of the loads of the several classes of service supplied determines the capacity required for any power system. This is expressed

by the term diversity factor, and is obtained by dividing the maximum load experienced during the given time interval into the sum of the maximum loads of each class of service, regardless of the time of occurrence. It is never less than unity. For convenience, its reciprocal is often used and as such miscalled the diversity factor. Where the diversity factor is high, less plant capacity, and thus less investment, are required than would be necessary where the diversity among loads is low.

56. Load Factor. — Load factor is a term used to describe the character of a load. It expresses the relation between the maximum load supplied and the average of all loads. It is computed by dividing the total kilowatt-hours supplied in any period of time selected, by the product of the maximum hour's load in that same period, and the total hours in the period; thus

$$\frac{\text{Supply in kwhr}}{\text{Maximum hour kw} \times \text{total hours}} \times 100 = \text{load factor in per cent}$$

It is designated "daily," "monthly," "annual," according to the period selected for computation. A relatively low load factor usually means that the load curve will show long hours of low loads and a few hours of high load. The opposite is true for high load factor. The curve in Fig. 14 shows a load curve with a relatively low load factor, and Fig. 15 one with a relatively high load factor.

Load factor has an important influence on operating costs. A plant supplying a load of low load factor will have many hours' use of equipment at light loads with a small total output. Since many items of plant operating cost, such as labor, are constant whether the plant is operating at or below capacity, an improvement in load factor, i.e., a filling out of the valleys, will increase the plant output and thus reduce the cost per unit of output.

57. Influence of Load Factor on Plant Design. — The load factor also influences the selection of plant equipment. It is a peculiarity of a steam plant and steam plant equipment that efficiency varies with the loading. There is a load at which the efficiency is the greatest. This may or may not be at the point of maximum rated capacity. At all other loads, the efficiency is less. Figure 18 shows a characteristic plant efficiency curve and one for the steam turbine installed in that plant. It is for this reason that for the design and selection of plant and plant equip-

ment a knowledge of the load factor of the load to be supplied is necessary. The load curve in Fig. 14 shows a load factor of 57 per cent. The maximum capacity required is 27,000 kw. The minimum capacity required is 6000 kw. Above this, the load varies from hour to hour until the maximum is reached. The average load is 15,400 kw. The load on this curve could readily

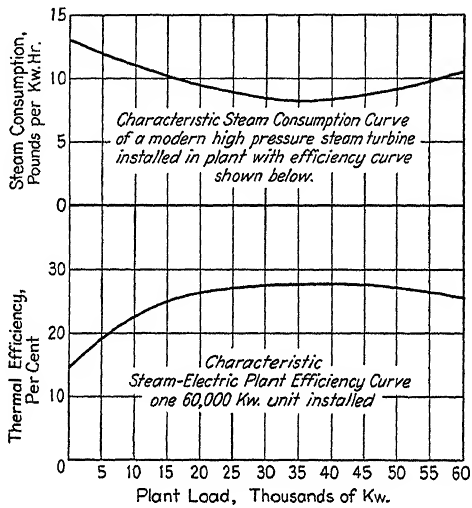


FIG. 18. Characteristic turbine steam consumption curve and electric power plant efficiency curve.

be supplied from one generating unit. But to do so, it would have to operate at or below half load for 15 hours, or five-eighths of the time. This is considerably below the efficient point on a steam turbine, unless the machine were especially designed for this particular type of service.

On the other hand, if two units are used, each to supply one-half the capacity required, one unit can be operated for the 15 hours at or near its best efficiency, and the other, although not so efficiently, for the period when the capacity required is greater than the capacity of one unit. That the use of two units will increase investment costs over the use of one, and that the large unit will probably be more efficient at rated capacity, are factors limiting the net savings from the use of two units.

This same principle of the use of load factor extends to the selection of any unit in the plant having a variable efficiency

curve. It will be shown later that it is not the only factor to be considered in the economical selection of size and number of units of equipment to supply a desired capacity, but it is one of great importance.

58. Capacity Factor. — This factor expresses the relation of the use of plant capacity to the total output of a plant. The annual capacity factor is computed by dividing the annual plant output in kilowatt-hours by the product of station capacity, using the sum of nameplate ratings, and 8760; thus

$$\frac{\text{Annual plant output kwhr}}{\text{Capacity kw} \times 8760} \times 100 = \text{capacity factor in per cent}$$

Annual fixed charges on investment in steam power plants are usually about one-half the total cost of power produced by the plant. The nature of fixed charges is outlined in detail in Chapter VI, Sections 93 to 101 inclusive.

These charges continue regardless of the number of hours a plant is operated. It therefore becomes evident that the greater the number of hours the plant capacity is used, the lower are the fixed charges per unit cost of the plant product. If the fixed charges per kilowatt are $13.50 annually and the plant is operated at 100 per cent capacity factor, i.e., 8760 hours, then the fixed charges per unit of output are $13.50/8760 or $0.00154. If the plant capacity factor is only 40 per cent, i.e., 3504 hours' use, then the fixed charges per unit of output are $13.50/3504 or $0.00385.

It is shown in Chapter VI that a part of plant operating costs is fixed and is as constant as the fixed charges. Capacity factor has the same effect on this part of operating expense as it has on investment.

59. Influence of Capacity Factor on Investment. — The unit cost of power is the sum of the unit investment costs, i.e., fixed charges, and unit production costs. The principal means of reducing production costs is to use more efficient heat absorbing and more labor saving equipment, with a corresponding larger investment. It has been demonstrated that long hours' use of equipment or high capacity factor reduces investment costs per unit of output. It is evident therefore that, if the load to be supplied will allow a plant to operate at high capacity factor, a larger investment for plant efficiency would be warranted than if the load produced a low capacity factor for the plant.

This effect of capacity factor on investment cost per unit of output is graphically shown in Fig. 19. In this figure, curve *A* shows one plant estimated to cost \$100 per kw with annual fixed charges at 13.50 per cent and a variable unit production cost of \$0.0022. The fixed component of operating expense is \$3.00 per

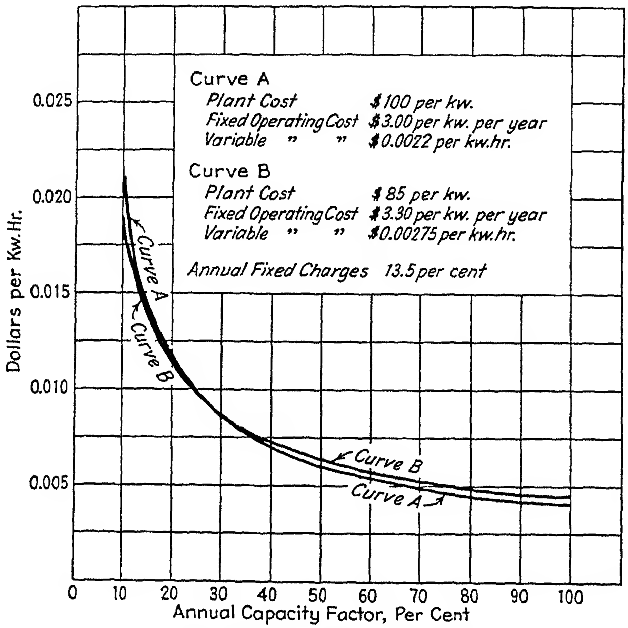


FIG. 19. Curve showing the effect of annual capacity factor on total plant power costs.

kw of capacity. Curve *B* is for a plant costing \$85 per kw, with the same rate of fixed charges and a variable unit production cost of \$0.00275. The annual fixed component of operating expense is \$3.30 per kw. Note that for the low capacity factors plant *B* shows a lower overall unit cost of power, and that as capacity factors increase, the curves approach until at capacity factors above 32 per cent plant *A* shows the lowest total cost.

60. Lifetime Capacity Factor. — The art of making electric power from steam has been a rapidly changing one. Use of electric power has increased and load growth has been rapid. New plants, as they have been built to take care of this load growth, have been made more efficient by the incorporation in them of the latest improvements and advances in the art of

power generation. Thus, plants originally built to operate on the base of the load curve, or at high annual capacity factors, have been superseded by the newer and more efficient plants and have been pushed up on the load curve to operate at lower capacity factors. Experience has shown that plants operate at the best capacity factor for the first three to five years of life, and that from then on the trend of capacity use is downward. This trend is illustrated in Fig. 39, Chapter XI.

It is therefore necessary to consider capacity factor on the basis of the average annual capacity factor during the life of the plant. The period of operation at low capacity factor may be so much greater than the few years at high capacity factor that an investment justified by the higher capacity factors obtained in the early years would not be warranted by the average.

61. Reserve Capacity. — The reserve capacity requirements of the power system to be supplied by a steam plant must always be considered in the design of that plant. If the system is not interconnected with other outside systems or if no other plants are to be operating in the system, a condition rarely encountered at present, the reserve problem is entirely different from that found in situations where the system draws on many sources for its supply. This difference is reflected in the plant design, in the size and number of units installed and in the total investment.

In an isolated plant, reserve capacity must be installed to provide for accident to or outage of any major unit, such as a turbine or a boiler. Although no fixed rule applies, usually enough reserve is installed to take the place of the largest unit, boiler or turbo-generator, in case that unit is out of service. For boiler reserve, advantage is often taken of the overload steaming capacity inherent in most boiler designs, provision being made for the higher combustion rate required by making the furnace and fuel burning equipment somewhat larger than necessary for normal loading. For turbo-generator reserve, where several units are installed, sufficient overload capacity may be available for this purpose. More frequently, however, additional turbo-generator capacity is installed without equivalent boiler capacity.

In power systems supplied by more than one plant, the plants being interconnected with adequate transmission lines, reserve is usually provided against the largest single unit in the system.

This reserve may represent 10 to 25 per cent of the total installed capacity. It is not provided in any one particular plant, but enough capacity is installed in all the plants so that the margin of capacity above the load requirement will equal the desired reserve. The present day trend is to install one turbo-generator unit with only one or two boilers to supply the steam. In case of the failure of any part of this combination, the entire group, boilers and generating unit, may be taken out of service and the reserve capacity from some other part of the system substituted. (See also Chapter II, Section 29.)

CHAPTER V

INTERNAL ECONOMICS OF STEAM POWER PLANTS

62. Objective in the Selection of Power Plant Equipment. — After the need of a power supply has been recognized, and the capacity required, fuel supply and location have been decided upon, the designer must next select the equipment which when assembled in the completed plant will produce the power in the amounts required and of the requisite reliability at the lowest total cost. Load data, present and prospective, must be assembled and analyzed, the annual average capacity factor estimated and many preliminary designs and cost estimates made. The objective should be to create a plant, not necessarily the lowest in first cost, but one which during its life will be best fitted to the needs of the power system it supplies. The process is largely one of trial and error until the best combination is found.

63. Importance of Steam Pressure and Temperature. —Probably no other single factor is as influential in shaping the design of a plant, in fixing its efficiency and in determining investment and operating costs as the operating steam condition. For each combination of fuel cost, load factor and capacity factor, there is an economical steam pressure and temperature which will produce the lowest total cost of power.

It is necessary, therefore, in the initial consideration of a new plant or additions to an existing plant, to determine the most suitable steam condition before it is possible to proceed with the design.

The thermal efficiency of a steam prime mover is improved if the temperature range through which the steam expands is increased. Since the lower limit is fixed by the vacuum which can be secured with the temperature of condensing water available for any plant, improvement in thermal economy must be obtained by raising steam pressures and temperatures. The gains from this procedure are shown by the curves in Fig. 20.

It is necessary, therefore, to determine the point at which the increase in efficiency due to increasing the steam pressure and

temperature ceases to support the additional investment in equipment required to secure the efficiency increase.

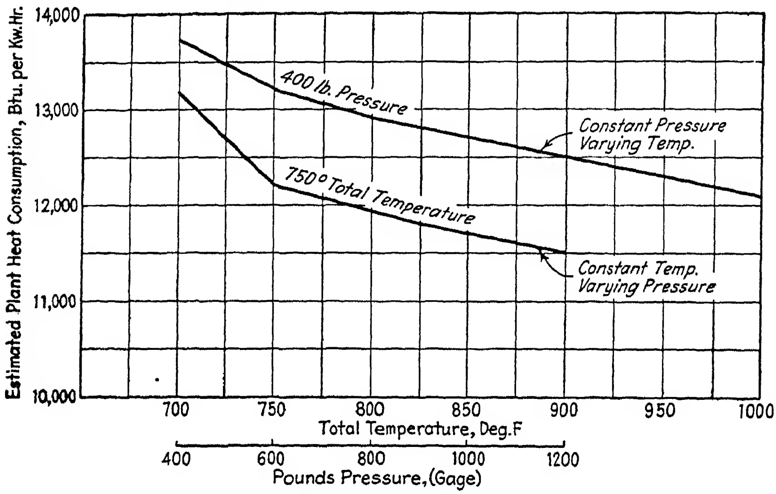


FIG. 20. Curves showing effect of varying temperature and pressure on steam plant performance (boiler efficiency constant for all conditions).

64. Use of High Pressure Steam May Increase Investment. — A power station designed to use steam at a relatively high pressure and temperature is usually more expensive to build than one using steam at a lower pressure and temperature. This is true not entirely because of the use of the higher pressure, but also because the same economic condition which justifies the additional cost of high pressure equipment — boilers, valves, piping, etc. — will also justify the expense of more efficient and additional equipment not directly affected by the steam pressure.

As steam pressures are increased, the efficiency of the boiler unit decreases. This is explained by the fact that when the steam pressure is raised, the temperature of the steam-water mixture in the boiler tubes is increased with a resulting equal increase in flue gas temperature. To prevent this loss, it becomes necessary to extend the boiler surface or to add air preheaters or economizers. Also, when the steam pressure is increased, the saturation temperature of the steam is increased, and since the total temperature is limited by the materials now in use, the amount of superheat above saturation temperature is decreased. As steam pressures are increased, a point is

reached, therefore, where, in the expansion of the steam through engine or turbine, because of excessive saturation, it becomes necessary to interrupt the flow and reheat the steam, necessitating some form of reheating equipment. For these and many similar reasons, plants become increasingly expensive as steam pressures are raised, and there is also a marked difference in the design.

Where the increase in pressure is not enough to make any great difference in design or equipment used, this may not be true. Under such circumstances, unit costs may even be lower, because high pressure steam equipment permits a given capacity to be installed in a smaller building, with all the resultant economies. It is probable that unit costs of construction decrease with increase in pressure as long as the design is the same, and increase abruptly as soon as the pressure condition requires a change in design in pressure parts and assembly. Between pressures of 400 and 700 lb, boiler construction and piping construction standards are the same, and because of this, the cost per unit of capacity is approximately the same. Above 700 lb pressure, there is a considerable change in design and costs increase rapidly.

65. High Pressure Steam a Commercial Success. — Increasing of steam pressures has been a commercial success. Wherever steam pressures have been increased, the results obtained have justified the extra investment involved. Prior to 1923, 400 lb was the highest steam pressure that had been used. Since that date, the development in the use of higher pressures has been rapid. In 1925, a 1200 lb pressure boiler and turbine was added to an existing plant by the Edison Electric Illuminating Company of Boston. This is said to have been the first commercial installation at that pressure in this country. Subsequent additions were made and the pressure raised to 1400 lb. Other central stations followed. Table 6 gives a partial list of large plants using steam pressures of 600 lb or more.

TABLE 6

Some Representative High Pressure Steam Electric Power Plants in the United States

Company and Station	Design Pressure, Pounds	Total Steam Temperature	Capacity, kw
Industrial Plants			
Philip Carey Mfg. Co., Lockland, Ohio	1800	820	5,000
Champion Coated Paper Co., Hamilton, Ohio	650	750	8,500
Waldorf Paper Products Co., St. Paul, Minn.	650	700	3,000
Solvay Process Co., Syracuse, N. Y.	800	750	5,000
Public Utility Plants			
Atlantic City Electric Co. and Philadelphia Electric Co., Deepwater, N. J.	1200	750	106,000
Edison Electric Illuminating Co., Edgar Station, Boston, Mass.	1400	700	35,000
New Jersey Power & Light Co., Gilbert Station, Holland, Pa.	1400	750	55,000
Kansas City Power & Light Co., Northeast Station, Kansas City, Mo.	1400	725	45,000
American Gas & Electric Co., Philo, Ohio	600	700	40,000
Jersey Central Power & Light Co., South Amboy, N. J.	1400	750	50,000
Public Service Co. of Northern Illinois, Waukegan, Ill.	650	725	50,000
Public Service Electric & Gas Co., Burlington, N. J.	650	825	18,000

66. Analysis of a Typical Problem in Selecting Steam Pressure to be Used. — Table 7 is a summary of an analysis made to determine steam pressure to be used in a new 50,000 kw plant serving a public utility system. Because of its location near the coal fields in Pennsylvania, fuel cost was very low. The average annual capacity factor expected was quite low because the hydro capacity in the system made it necessary to shut the plant down over week-ends during the high water periods. The daily load factor was usually high, as well as the monthly load factor in some of the summer months.

A great many plant designs and estimates were made. The ones selected for comparison seemed the most representative ones in each pressure group. No consideration was given to the fact that the use of higher steam pressures might increase operating expenses, particularly maintenance. In each case the boiler plant was designed for 86 per cent efficiency. Four hundred pounds was adopted as the most suitable for the plant. Detailed study later proved that with the low price of fuel, the cost of installing equipment to obtain a station performance of 14,000 Btu per kwhr was not justified. Therefore, in the final design, the station heat rate was increased and plant cost decreased with a resulting lower total power cost.

TABLE 7

Summary of Analysis made to Determine Steam Pressure for a New Plant

	Preliminary Design			Final Design
Steam pressure, lb gage	400	600	1200	400
Total temperature, deg.	750	750	750	750
Reheat, deg.	0	525	750	0
Plant capacity, kw	50,000	50,000	50,000	50,000
Annual capacity factor, per cent	45	45	45	45
Station generation, gross	197,100,000	197,100,000	197,100,000	197,100,000
" " net	188,230,000	187,300,000	185,275,000	188,300,000
Fuel cost per million Btu	$0.085	$0.085	$0.085	$0.085
Btu consumption per kwhr, gross	14,000	13,100	11,900	14,850
Cost of plant	$4,400,000	$4,675,000	$4,835,000	$4,195,000
Annual fixed charges @ 13.5 per cent	$594,000	$631,125	$652,725	$566,325
Annual fuel costs	$234,549	$219,471	$199,367	$248,788
Other annual operating costs	$235,000	$235,000	$235,000	$235,000
Total annual power cost	$1,063,549	$1,085,596	$1,087,092	$1,050,113
Cost per net kwhr	$0.0056	$0.0058	$0.00587	$0.00557

The final design might be criticized on the grounds that an increase in fuel cost as small as 6 per cent would wipe out the annual savings due to lowered fixed charges, and that the initial

400 lb design should have been chosen. In many cases, this argument would be sound. The engineers claimed, however, that, since the source of fuel supply was controlled by the company proposing to build the plant, it would not be subject to the same price fluctuations as fuel bought in the open market. The estimated annual capacity factor is higher than that to be expected in most cases (see Fig. 39, Chapter XI), but represented the judgment of the engineers based on their own experience in the particular system this plant was to serve. A decrease in this factor would favor the final design selected.

67. Summary of Factors Affecting Choice of Plant Pressure and Temperature. — The selection of the economical steam pressure depends entirely upon the proper balancing of fuel savings against increased investment costs. It will be found that high pressures are used where fuel costs are high owing to the

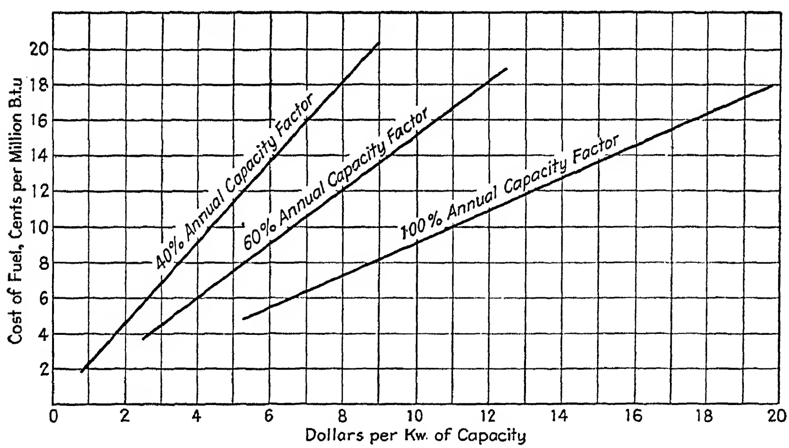


FIG. 21. Additional investment justified by the fuel savings of a 1200#, 750° steam plant over the cost of a 400#, 750° steam plant at various fuel costs and capacity factors.

possibility of greater total savings when the fuel consumption is reduced. Figure 21 shows the effect that increasing fuel costs have on allowable investment costs. With a 400 lb, 750° steam station representing the base cost, there has been calculated at various capacity factors the increment investment allowable for a 1200 lb station at various fuel costs.

68. Economic Considerations Leading to Selection of Turbines. — The selection of turbines of the proper size and number

for a required capacity depends on the economic situation under which the plant is built and operated. The basic factors to be considered in the economical selection of turbines are size and rate of growth of load in the system to be served; capacity and load factors at which the plant will be operated; thermal efficiency as determined by the price of fuel; reliability and availability factors; location of plant with respect to condensing water available and cost of real estate, and low final total cost of plant.

Because of these factors, and because the varying costs of fuel lead to the use of different steam pressures, temperatures and exhaust conditions and to modifications of the plant heat cycle, it is not unusual that wide diversity in designs and arrangement of equipment and in the selection of size and number of turbines results.

69. Size of Turbines. — Before the interconnection of large power systems, the load available and the expected growth of the load determined the capacity to be installed. All that was then necessary was to divide the capacity into sufficient units to provide the requisite reliability and availability of service. These considerations are still important, but no longer fundamental. Interconnection of isolated power systems, and merging under one corporate management of adjacent power systems, have created loads much beyond the capacity of one unit or one station to serve. With the large loads so created, and with improved load factors and a greater percentage of the total load in the base, it quite frequently works out that the most economical selection is the largest machine that can be installed, limited only by the size of building or plant site or the ability of the manufacturers to produce. Such units operate as base load units and have high annual capacity factors.

70. Economic Reasons for Use of Large Turbine Units. — The economic reasons for this use of large units are many. As turbine size increases, weight and floor area per unit of capacity decrease. Cost likewise decreases. Complete analyses of the cost of many different plants, designed and built to satisfy widely varying conditions, indicate that overall first cost of station per unit of installed capacity decreases markedly with an increase in the capacity of the turbine.

Therefore, the trend for a number of years has been progressively towards units of large capacity. In Table 8 are listed a

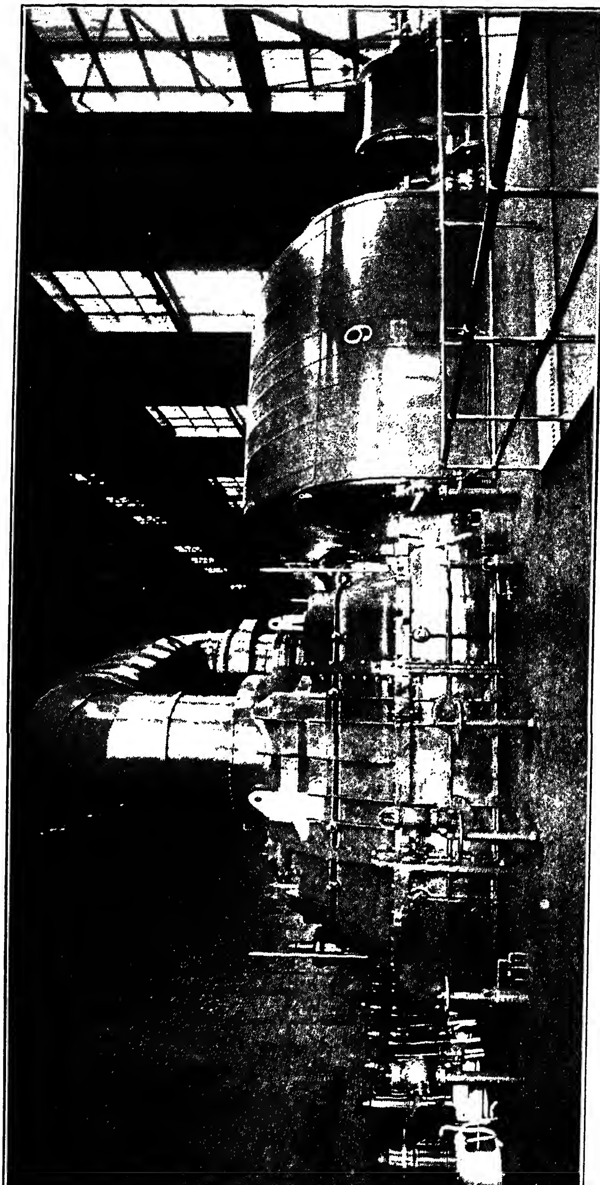


FIG. 22. Typical large steam generating unit. 165,000 kw cross compound turbo-generator at Hell Gate Plant of New York Edison Co. (Courtesy of Westinghouse Electric and Manufacturing Co.)

number of notable installations of large units made in recent years.

TABLE 8

SOME REPRESENTATIVE LARGE GENERATING UNITS INSTALLED IN PUBLIC UTILITY POWER PLANTS

Company	Name of Plant	Capacity of Unit, kw
New York Edison Co.	Hell Gate	160,000
New York Edison Co.	Hudson Avenue	160,000
Philadelphia Electric Co.	Richmond	60,000
Philadelphia Electric Co.	Richmond	165,000
Southern California Edison Co.	Long Beach	100,000
Duquesne Light Co.	Colfax	60,000
Niagara Hudson Power Co.	C. R. Huntley	80,000
Chicago District Elec. Generating Corp.	State Line	208,000
Union Electric Light & Power Co.	Cahokia	50,000
New Jersey Power & Light Co.	Gilbert	55,000
The Cleveland Electric Illuminating Co.	Lake Shore	50,000
Public Service Electric & Gas Co.	Kearny	75,000
Milwaukee Electric Railway & Light Co.	Washington	80,000

Operating economies are also effected by the use of large units. Labor costs (see Chapter VI, Section 103) as well as steam consumption are decreased. Figure 20 shows that, by increasing temperatures and pressures, the station heat consumption can be decreased. At these higher pressures and temperatures, the greater density of the steam is of decided advantage to the designer of large capacity turbine units. Therefore, as units have increased in size, steam pressures and temperatures have increased with a resultant lowering of steam consumption and increase in station efficiency.

71. Load Growth and Load Factor, as Influencing the Selection of Turbines. — There are still some plants which do not operate as part of an interconnected group, or which do not have loads warranting units of very great capacity. For these plants, rate of load growth and load factor are still important considerations in selecting size and number of units.

In the example in Chapter IV, Section 57, it was shown that two units would carry the load and give better overall economy than one. If in this example each unit were made equal to one-half the indicated load, even a slight increase in load would re-

quire the installation of another unit, which might, for a long time, have to operate only partially loaded. Therefore, rate of load growth often indicates that certain sizes of units be installed as required by the increasing demand. Installation of units without some provision for future load growth would, in many cases, necessitate too frequent plant additions, the plant would not be as efficient as one with larger units and the investment per unit of capacity would be greater.

72. Reliability and Availability as Affecting the Choice of Turbines. — The power user requires not only an adequate but also a reliable supply of power. This conception of the needs of the power user on the part of the producer is one reason for the great increase in the use of electricity in industry. Therefore, not only must turbine units operate for long periods of time without interruption, but also the periods of interruption or shut-down must be of short duration. Records of turbine performance collected by N.E.L.A. Prime Movers Committee on "Steam Turbines," 1928–29 report, indicate that availability is improving, and that for 207 turbines of 20,000 kw and over, on which data were collected, the availability factor averaged 90.31 per cent, the availability factor being defined as the ratio of total time during which load was available to the time during which the machine was operated or in operating condition.

73. Reserve Capacity Requirements as Affecting the Selection of Turbines. — Another element in reliability of service is the reserve capacity which must be provided. Increasing reliability and availability of turbines, due to improvements in both design and operating technique, have made it unnecessary to split the plant capacity into a number of small units to provide reliable service.

This condition has also been assisted by the interconnection of systems and a pooling of reserves. In systems of moderate size, particularly where interconnections do not exist or are of small capacity, too large a unit is not advisable because of the reserve required to back it up with a consequent increase in plant investment costs. (See Chapter IV, Section 61.)

74. Influence of Plant Site on the Selection of Turbines. — The quantity of condensing water available limits the capacity of a plant, but has no influence on the size and number of units selected to produce that capacity. The cost of real estate, however, does have a marked influence on the proper selection of

turbines as well as other equipment. In or near metropolitan areas, land is expensive and taxes are high. It is necessary, therefore, for the designer to obtain as much capacity per square foot of area as possible. The largest units that can be installed because of their low space requirements per unit of capacity are therefore used in plants for service to these areas. Because of the savings this creates in fixed charges, many other elements necessary to be considered where land is relatively cheap become of secondary importance.

75. Summary of Factors Affecting Choice of Turbines. — With so many factors involved, it is probable that more than one combination of generating units will produce the same result. Some plant designers with a pioneering spirit will adopt high pressures and supersized units to obtain high economy; others less daring will seek by conservative design and skill to offset relatively lower economy by a reduction in investment cost. A nice balancing of the many elements is necessary in either case to achieve the desired result.

76. Factors Affecting Selection of Condensers and Other Turbine Plant Equipment. — The function of the condenser is to reduce the back pressure at the turbine exhaust. Theoretically, at least, the lower this pressure, the better the performance of the turbine and the lower the turbine steam consumption. Back pressure reduction or better vacuum is obtained either by increasing the size of the condenser and the heat exchanging surface, or by increasing the quantity of condensing water pumped, or by both. The economical selection of the condenser, therefore, becomes one of balancing the saving due to decreased steam consumption by the turbine against the increased fixed charges incurred by the extra cost of increasing the condenser surface, and to the increased pumping costs, to obtain the lower back pressure.

Much of the other turbine plant equipment, such as piping, pumps, etc., is necessary for the satisfactory operation of the plant, but cannot be always evaluated in terms of fuel or labor savings. Probably the prime considerations in the selection of this equipment are ability to perform efficiently the functions required and freedom from operating difficulties and high maintenance costs.

77. Selection of the Plant Operating Cycle. — The plant operating cycle, often referred to as the plant "heat balance,"

determines the thermal efficiency at which the turbine plant can operate. The term "heat balance" is generally used in connection with the method used to heat the feed water. In any steam power plant, at any given load, there exists a feed water temperature at which the efficiency of power generation is at a maximum. For large condensing power stations, the generally accepted method is to use all electrically driven auxiliaries and to extract steam from the main unit at several points in its path to the condenser, using the heat of this steam to raise the feed water to the desired temperature.

The problem of economical selection of the amount of steam extraction and the number of heaters to be used is one of balancing the thermal gains, evaluated in terms of fuel, against the increased fixed charges and operating costs on the additional equipment required. Fuel costs are the controlling factor — the greater the cost the greater the investment possible in perfecting the heat balance. With the many arrangements of pumps, piping and heaters that can be made, the selection of the economical "heat balance" is one of the most difficult tasks imposed on the plant designer. Once determined, it affects so many other elements in the plant that changes are often difficult, if not impossible, to make.

78. Selection of Boilers and Furnaces. — The economical selection of boilers is subject to many of the same influences affecting the economical selection of steam turbines. The trend is toward units of large steam producing capacity. Early steam power plants were noted for their multiplicity of small boiler units. To obtain sufficient steam capacity, plants located in areas of high land values had boilers installed on two or more floors. This condition was brought about not by any limitations in the boiler itself, but because of the inability of the combustion facilities then in use to burn the fuel at the required rates and because of the inability of the furnace refractories to withstand the punishment caused by high combustion rates. Development of the water cooled wall for furnaces, pulverized fuel firing, and improvement in mechanical stoker design have changed this. Boilers capable of producing up to 1,000,000 lb of steam per hour are now in service.

79. Effect of Size of Boilers on Steam Plant Investment. — Investment per unit of capacity is lowered by increasing the size and decreasing the number of boiler units. This is brought about

by a number of factors, more or less related. The capacity of a boiler is usually increased by increasing its width. Since the perimeter does not increase at the same rate as capacity, the setting costs do not increase proportionally, and the unit cost is less.

Building costs are also reduced with large boilers. A minimum of aisle space is required between the boilers installed, regardless of size. If the number of boiler units is decreased, fewer aisles are needed, thus causing a reduction in building space with all the attendant savings in steel work, foundations and other building costs.

Pipe connections for large boilers are larger than those for small boilers, but the cost of the piping required for one large boiler is less than the cost of the piping for two or more boilers delivering the same capacity. This principle also holds for all other boiler auxiliary equipment. In a paper in A.S.M.E. Proceedings — Vol. 52, No. 27, page 243, Sept.–Dec., 1930 — Mr. Frank Clark discusses the effect of size of boiler on plant cost, showing by detailed studies the effect of large capacity boilers on unit capacity costs and the marked decrease in these costs when large boilers are installed.

80. Other Factors Influencing the Selection of Boilers. — The effect of size on investment is not the only measure in selecting boilers. Load and capacity factors, reserve requirements in the plant and system and availability must also be taken into account. They are all closely interrelated.

The steam production of any boiler is limited principally by the quantity of fuel that can be burned under it. If the load curve shows a peak of short duration, but considerably greater than the average load, in other words, if the load factor is low, it is usually more profitable to install boiler surface which will be most efficient at the average load and sufficient fuel burning equipment to lift the output to the capacity necessary to carry the peak in spite of the loss in efficiency. Reserve is often handled in the same manner, using this so-called overload capacity of the boilers as reserve in case of the failure of a boiler unit. In this manner, investment costs in boiler capacity are decreased.

Perhaps the only factors to be considered in selecting boiler units are those relating to first cost of the equipment and maintenance and labor costs. Overall plant efficiency is very little

influenced by size and number. There is some variation with the different types of boiler, but this is usually compensated by the efficiency of other auxiliary equipment. There is a limit to the number of boilers one man can attend, and a multiplicity of units tends to increase labor costs. But because investment costs are the determining factor, boiler units are increasing in size and rating with the ultimate goal of designers in sight, a power plant in which is installed only one boiler unit per turbine unit.

81. Selection of Fuel Burning Equipment. — In the choice of fuel burning equipment, the same path is followed as that in the selection of boilers, especially if coal is the fuel. Efficiency as a factor in the economical selection of this equipment is of secondary importance. Most standard equipment in properly designed furnaces will burn coal with equal efficiencies.

The choice between different types often narrows down to the relative fuel burning capacity in a given space, or in other terms, to the relative combustion rates per cubic foot of furnace volume or of building volume. In localities where coal is available from many different fields, the ability of pulverized coal equipment to burn any or all of them, regardless of quality, often outweighs any advantages in cost or efficiency afforded by the use of other equipment. On the other hand, the fly ash nuisance often created by the use of pulverized coal may outweigh this advantage. Recently, one central station selected stokers because of the difficulty experienced in another plant in disposing of the fine ashes produced by pulverized coal. If for any reason stokers are desired, the characteristics of the coal to be burned often limit the choice to one type.

82. Selection of Other Boiler Plant Equipment. — Fuel cost is the controlling factor in the selection and proportioning of heat traps, such as air preheaters and economizers. With either an economizer or air preheater, it is possible to make substantial reductions in the temperature of the boiler flue gas with corresponding fuel savings. But the use of this apparatus necessitates a radical change in design and arrangement, and there may be increases in operating expenses, so that the increment saving must be quite substantial to justify their use. The fuel saving from which is deducted the additional liabilities incurred by the installation, stated in per cent return on the investment, is the usual criterion for the selection.

Where economizers or air preheaters or both are to be used, an economical balance can be found between the amount of boiler surface, preheater surface and economizer surface which can be installed to give the desired efficiency at a minimum cost. An interesting exposition of this subject was recently published in the March 4, 1930, issue of Power, page 358, by Mr. Linn Helander, in which the author presents original formulae for the solution of problems of this nature.

83. Responsibility of Manufacturers Should Be Considered in Selecting Equipment. — One element often disregarded in the selection of steam power plant equipment is the ability and responsibility of the manufacturer offering the equipment for sale. In economic comparisons, particularly, it is assumed that the only differences between apparatus are cost and efficiency. It should not be forgotten that fixed charges on a plant are based on an expected operating life of 15 to 20 years. Often, equipment selected only on the basis of cost begins to develop faults after a few years' service which even the most conservative plant designer could not anticipate. The cost then of maintenance and replacement parts due to use of poor materials or shoddy designing in a desire to lower the price often causes economic losses much greater than the savings that appeared possible when the apparatus was first chosen. Due weight should always be given, therefore, to the integrity, experience and responsibility of the apparatus manufacturer.

84. Rehabilitation of Old Power Plants. — The past decade has witnessed many changes and improvements in the art of steam power generation. Steam pressures ranging from 400 lb to 1400 lb have been adopted. Water walls for furnaces, air preheaters and many other devices have been developed to improve boiler efficiencies. Boiler plants in high cost fuel districts are now designed to attain 86 per cent efficiency, whereas ten years ago 75 per cent was the goal. Boiler units of large size capable of generating 1,000,000 lb of steam per hour have been placed in operation. In the turbine room, there has been a rapid increase in the size of units. Higher pressures and temperatures have materially increased the efficiency of turbines. The regenerative and the reheat-regenerative cycles have been developed to a point where the fears expressed in the early discussions of their practicability have been entirely dispelled.

85. Economic Bases for the Rehabilitation of Old Power Plants. — It is possible to adapt these developments to many plants built before this era of rapid improvement began, to increase either capacity or efficiency or both. There are numerous reasons why it may be economical to do this.

Suitable sites for steam plants are difficult to secure in metropolitan areas or are already occupied by plants strategically located with regard to load distribution and having already available transmission and distribution facilities. Or the system may require a small increment of capacity which, if provided by the building of a new plant, would make necessary considerable expansion beyond present needs in order to obtain the advantage of low unit investment cost. Frequently, old plants were built with insufficient boiler capacity. An increase in boiler capacity by means of high efficiency new boilers will not only improve the overall efficiency but also increase the firm capacity of the plant. The form taken by the improvements will be determined and limited by the factors of condensing water supply, fuel supply and ability to increase the capacity of the already available transmission and distribution facilities.

86. Increase of Capacity Limited by Transmission Facilities.— Inability to increase the transmission and distribution facilities in an old plant will probably prohibit any program involving the increasing of generating capacity. Boiler room economy may be increased, however, at a comparatively low cost by altering combustion chambers, fuel burning equipment or boiler baffling, or by installing air preheaters, economizers or both. Labor costs can be lowered by modernizing ash and fuel handling equipment. The use of furnace water walls will not only increase steam production, but also materially reduce furnace maintenance costs.

Overall plant efficiency may be bettered by increasing steam temperatures and altering turbine casing and wheels to suit. Such an alteration would be rather expensive and probably could be justified only by high load factor operation. The substitution of electric motor for steam drives on plant auxiliary equipment or the replacement of these steam drives by more efficient ones, exhausting into a closed feed water heating system, would result in improved plant efficiency.

87. Increase of Capacity of Old Plants. — Where increased station capacity is desired, as well as added economy, the instal-

lation of high pressure boilers which feed a high pressure turbine which in turn exhausts into headers supplying the existing low pressure turbines has many possibilities. Such a program may be carried out to the extent that all of the steam required for the old low pressure plant will first pass through high pressure turbines. If the condensing water supply is limited, the introduction of a mercury unit may be desirable. With such an arrangement, since the capacity provided by the mercury unit does not require a condensing water supply, about twice the capacity can be secured with the same quantity of circulating water required by an all steam plant operating at 400 lb pressure. Although the introduction of the mercury unit has not been rapid, its use and advantages in this field are well understood.

The fuel and other economies which can be obtained from adding either the high pressure turbine installation or the mercury unit are quite large and may support considerable investment for this purpose.

88. Some Recent Examples of Old Plant Rehabilitation. — The Public Service Company of New Jersey has recently furnished two good examples of plant improvement and salvaging investment in old plants. The Burlington, N. J., plant was built in 1918. In it were installed three 11,000 kw turbines supplied with steam at 200 lb. Recently, an 18,000 kw unit was installed to operate at a pressure of 600 lb and temperature of 825° F, exhausting at 200 lb to the old units. This new unit, together with the three old units, operate as a compound machine. The old boilers were shut down, and in case the high pressure unit is out of service, steam from the 600 lb boiler is supplied to the low pressure units through a reducing valve. Changes were also made at the same time to the station auxiliary equipment to improve the heat balance. The overall efficiency of the plant was increased approximately 70 per cent.

At the Kearny, N. J., plant of the same company, a mercury unit of 20,000 kw is being installed. Not only is an increase in plant efficiency expected, but also the steam generated as part of the mercury cycle makes it possible to avoid installation of additional boiler capacity for the existing steam driven units.

The Lakeside plant of the Milwaukee Electric Railway and Light Company had one of the pioneer high pressure (1200 lb) installations in which the high pressure turbine unit exhausted into the low pressure steam headers. The capacity of the high

pressure unit of 7000 kw represented approximately 4 per cent of the total plant capacity. This company reported to the Prime Movers Committee of the N.E.L.A., serial report 289-73, that the installation of this unit effected a reduction of approximately 6 per cent in the consumption of heat by the station.

CHAPTER VI

COST OF STEAM ELECTRIC POWER

89. Investment Cost. — The total cost of producing power, like that of any other manufactured product before distribution, is the sum of two costs, each of which must be balanced with the other to give the lowest total cost. The first is the cost of consumable products, labor, coal and other materials, entering into the manufacturing process, and is known as the production cost. The second is the cost created by the money spent to build the plant and is known as the annual investment cost or fixed charges. Production costs can be decreased by an increase in investment, but if the increased investment is made without proper consideration of all economic factors, the total cost may be greater than it would have been if less money were spent. Conversely, if too little money is spent, production costs are increased and total costs may be higher than the economic situation warrants. It is for this reason that the designer and assembler of power equipment proceed carefully to select each part, balancing the cost of each against the work it will do and the efficiency at which it performs. The total plant cost represents the sum of the costs of all these parts, plus the cost of assembly and buildings, and the many other costs incurred in the design and construction of the plant.

While the average performance in Btu per kwhr of steam plants is still high, the best plants approach the ultimate possible with the present knowledge of the art. This leaves the investment cost the only field for possible improvement and reduction in the total cost of power. To lower this cost without increasing production costs is the present endeavor of most power engineers. Larger units, with one boiler for each unit, interconnection of systems, simplicity in design with elimination of much duplication of equipment, and stations with only a minimum of building for the protection of the operators are some of the means taken to accomplish this result.

As a yardstick to measure the result of his work and to compare it with the work of other engineers, the designer often uses

the investment cost per unit of capacity installed (cost per kilowatt of installed capacity). This method is not an absolute measure of investment efficiency, and unless used with a full understanding of the conditions surrounding the design and construction will lead to erroneous and unsatisfactory conclusions. It is affected by many conditions, both within and beyond the control of the designing and construction engineers.

90. Conditions Affecting Investment: *Location.* — Location as affecting relative cost of power stations is an important factor. Steam power plants of any appreciable capacity must be located near an adequate supply of water for condensing purposes. Many diverse soil conditions — swamp, rock, gravels — are thus encountered, leading to wide variation in foundation costs. In some instances, the foundation problem is relatively simple; in others, expensive piling is required, with many intermediate variations. On the Delaware River, foundations must be built for a difference in water level from maximum to minimum of only six feet. On the Mississippi, this range may exceed sixty feet. It is evident that the foundation construction is quite different in the two cases and more expensive in the latter than in the former. The cost of intake structures and intake lines is also influenced by the varying soil and water level conditions encountered.

Manner in which Fuel is Received. — The manner in which fuel is received is reflected in the cost of fuel handling and storage facilities. Water borne coal usually requires considerable investment in docking facilities. Similar costs are not required where the coal is received by rail. The unloading plant for water borne coal must often be much larger than is required for rail deliveries, even though the quantities to be handled are the same, because of the necessity of rapid unloading to avoid excessive demurrage charges on the boats.

In oil or gas burning plants, unless the oil is received in tank ships, dockage facilities are not required. Unloading equipment for oil is simple and inexpensive. No investment is required for storage in gas burning plants.

Value of Plant Site. — Land values are reflected in the cost of plants, not only by the cost of the land itself, but also by the effect land costs have on the plant arrangement. Where land is very expensive or difficult to obtain, as often is true in metropolitan areas, the urge is to get the maximum capacity per

square foot of available area, even at the expense of good design. When this is the case plant buildings tend to be high, with many operating levels, and equipment is often crowded. These conditions influence not only investment but also production costs. Where cheap land is available, the resulting design is quite different.

Electrical Distribution. — Often a plant is required to serve a local load with many circuits at distribution voltage leaving the building. In other cases, the supply is through an outdoor step-up substation to the transmission system. The first plant requires a much larger investment in electrical equipment and building than the second. Comparison is often attempted by eliminating plant substation costs, but the results are seldom satisfactory.

Size of Load. — In large systems supplied from several plants, new plants are built with units as large as it is physically possible to install, or as large as can be fitted to the load curve, with resulting low unit costs, and because the supply is from a number of plants, little or no additional reserve is provided. On the other hand, a single plant serving a small system must have smaller units and all the system reserve must be installed in the one plant. (See Chapter V, Sections 68 to 73 inclusive.)

Architectural Treatment. — Some managements prefer, as a matter of policy, to house power plants in expensive buildings of the monumental type. This may be advisable as an advertising feature or where the plant is situated near a residential section of the community. Other managements are not so inclined. Comparison between building costs under these conditions is obviously unsatisfactory.

Fuel Cost. — Fuel represents the largest single item in the production cost of power. It is, therefore, the controlling factor in plant investment. A low cost of fuel will not support much optional investment in equipment for efficiency. On the other hand, a high fuel cost necessitates additional investment in equipment to permit fuel savings. Where the cost of fuel differs widely in two plants, the one with the lower fuel cost will have less investment in fuel burning and heat absorbing equipment than the one with high fuel costs, and the total unit investment should be less for the plant burning the low cost fuel.

Development Program. — Some plants are built in steps, each step a part of an ultimate program. It is often necessary to

provide in the initial step condensing water intakes, coal handling and storage plant and other facilities for the subsequent additions. In such a situation, unit costs for the first step are often very high, whereas for the increment steps it is very low. Comparisons where this condition exists are therefore difficult and unsatisfactory.

91. Summary of Conditions Affecting Investment. — To summarize, the items of investment may be divided into three general classifications:

(*a*) Those affected by the plant location, the characteristics of the site selected, the type of fuel and its unloading and storage.

(*b*) Those affected by the size and number of units, reserve equipment, size and character of building and manner of electrical distribution.

(*c*) Those affected by the thermal efficiency.

From cost data obtained from the building of a number of plants and from many estimates, it has been found that the relative proportion of each of these classes is approximately as follows:

(*a*) Fifteen per cent of total cost.
(*b*) Forty-five per cent of total cost.
(*c*) Forty per cent of total cost.

Of these three items, (*c*), which represents 40 per cent of the total cost, is influenced by the fuel cost and is wholly controllable by the designer; (*b*) is only slightly responsive to the efforts of the designer, and (*a*) practically not at all. Table 9 is presented to show the unit cost of three plants, subdivided into general classifications covering the principal cost items. Each plant used coal as a fuel. Plant *A* had the lowest cost for fuel, but was located on the Ohio River, and this location was reflected in the high unit cost for substructure. In plant *C* the fuel cost was about twice that in plant *A*. Plant *B* was unusually favorably located in all respects, with a fuel cost about midway between the two.

Note how closely the cost of the controllable items in plants *A* and *B* agree. Plant *C*, located in a metropolitan district with higher fuel costs, shows the effect of this in its cost for land and for mechanical (thermal) equipment. Plants *A* and *C* were built with provision for future expansion; plant *B* was not.

TABLE 9

UNIT COSTS OF THREE TYPICAL STEAM ELECTRIC POWER PLANTS

	Plant *A*	Plant *B*	Plant *C*
Plant capacity	70,000 kw	70,000 kw	185,000 kw
Number of units	2	2	6
Cost per kw of capacity:			
Land, fill, etc.	$4.55	$2.94	$12.60
Building substructure	15.03	5.33	4.97
Building superstructure	8.17	8.95	21.40
Building trim	1.15	0.88	1.78
Building equipment	0.45	0.35	2.72
Mechanical equipment	24.45	22.38	30.03
Electrical equipment	24.90	20.56	28.68
Service equipment	7.85	2.80	16.45
Substation	4.16	1.40	10.67
Engineering and construction expenses	27.12	17.46	20.42
Total cost per kw	117.83	83.05	149.72
(*a*) classification	22.56	11.20	21.57
(*b*) classification	54.84	38.19	72.80
(*c*) classification	40.43	33.66	55.35

92. Measure of Investment Efficiency. — If the cost per kilowatt of capacity is not a satisfactory yardstick for measuring the efficiency of the work of the designer and constructor, how can this be measured? The objective is to produce the lowest total cost of power. Since the uncontrollable variables affecting investment are numerous and since in no two situations can be found exactly the same fuel costs, labor costs or load curve, the answer is that there is no precise method of comparison. The designer must prepare many designs and estimates, weighing all the economic factors in the process; only by such studies can he be certain that he has solved the problem in keeping with the economic situation. He should be interested not in obtaining a plant with a unit investment lower than that of some other plant, but the one best suited to the needs of his company. Table 10 gives comparative investment and production costs for nine large representative central stations. Each represents the considered thoughts of a group of engineers. The wide variation in results is apparent.

93. Fixed Charges. — The fixed charge, as previously mentioned, is one of the two costs of producing power and is that

TABLE 10

COMPARATIVE INVESTMENT AND PRODUCTION COSTS FOR NINE REPRESENTATIVE CENTRAL STATIONS

Plant No.	A	B	C	D	E	F	G	H	I
Capacity kw	150,000	60,000	335,000	187,000	235,000	80,000	30,000	180,000	145,000
Number of units	3	2	8	6	4	2	2	6	4
Cost per kw of capacity	$97.97	$105.17	$107.90	$121.85	$114.20	$122.34	$124.94	$125.74	$133.55
Fuel cost per million Btu	0.15	0.16	0.18	0.15	0.15	0.095	0.10	0.18	0.125
Fuel cost, mills per net kwhr	2.32	3.44	3.60	3.57	3.11	1.97	1.32	3.61	2.61
Other costs, mills per net kwhr	1.22	0.86	1.54	0.76	0.75	0.93	1.37	0.98	1.28
Fixed charges per kwhr $13\frac{1}{2}$% fixed charges and 45% capacity factor, mills	3.35	3.60	3.69	4.15	3.91	4.18	4.26	4.30	4.56
Total cost mills per kwhr	6.89	7.90	8.83	8.48	7.77	7.08	6.95	8.89	8.45

cost created by or appertaining to the investment made. It is a cost that is "fixed" because it is continuing from year to year and does not vary with the output of the plant. From the standpoint of the engineer, it is considered to consist of three elements: cost of money; taxes and insurance, and depreciation and obsolescence.

94. Cost of Money. — The individual or corporation investing money in an enterprise demands an annual income from the investment commensurate with the risks involved. If a part of the money used must be borrowed from the public by the issuance of bonds or other forms of fixed income bearing securities, the income from the investment should be sufficient to attract these public funds and so maintain the credit of the enterprise that when additional money is required it will be forthcoming. The weighted average of the income requirements of these elements is the "cost of money."

95. Taxes and Insurance. — Steam power plants are subject to taxes the same as any other form of property. The manner in which these taxes are applied is largely dependent upon the state and community in which the plant is situated. In addition to the property tax, many other taxes are levied against a business, such as gross receipts taxes, corporation and franchise taxes of various forms and the federal income tax on net profits. The theory is often advanced that the power plant should bear a share of all these taxes, the ratio of the investment in power plant to total investment determining the amount of taxes to be assessed against the power plant. For accounting and some other purposes, this may be advisable. In economic studies, to do this would needlessly complicate the work, and it is not necessary.

It is difficult to see just how the building of a new plant will increase the gross receipts for a business. It is true that a new plant may increase net income, and the income tax to be paid, but since the tax is only a part of the net income after the tax there must still be some net income remaining, hence the deduction of this tax from net income will not affect the relative value of one project in comparison with another. This is true where the study is to determine the relative value of investments under the same management, and where the method of financing is the same in all cases, so that the relationship between borrowed funds and equity money is always the same. In interconnection studies (see Chapter XIII) between companies under

separate corporate management, where relationship between borrowed money and equity money may be different, income taxes should be included in the tax portion of fixed charges. The reason for this is that interest on bonded indebtedness is considered a part of expense and is therefore not taxable. Two projects may each yield the same income before interest on borrowed funds. The one having the larger ratio of this kind of money in its investment will have less net income subject to taxes than the one with the smaller ratio. Because of the various forms of taxation, it is sometimes difficult to say just which taxes must be included in the fixed charges, but a safe rule is to include only those taxes which are definitely brought about by the investment, or which vary according to the nature of the investment or its location.

Every well managed company provides insurance against the many kinds of loss or damage to which property is subject. There is fire insurance on that portion of the plant subject to such damage, boiler insurance, machinery breakdown insurance, several forms of liability insurance, elevator and workmen's compensation insurance. Some or all of these are ordinarily carried in varying amounts, depending upon the needs and judgment of the management. In some cases, the insurance is provided through the payment of premiums to insurance companies; in others, there is set up a reserve out of earnings for reimbursement in case of loss. The annual cost varies considerably because of the several forms of insurance, varying amounts carried and the hazards involved. However, in each case it can be determined as an annual percentage of the total investment, and thus be considered a fixed charge against that investment.

96. Depreciation and Obsolescence. — The owner of a power plant knows that at some time in the future, for cause or causes over which he has but limited control, the plant will no longer be useful to him in the conduct of his business. It is necessary to provide a reserve fund against this time, either to be used to replace the facilities no longer useful or to return the money used to the investors. This fund is accrued out of the revenues of the company, but the basis for this accrual must be the amount invested. Many methods have been devised to determine the sums that must be set aside for this purpose. Because of its general acceptance by engineers, only the sinking fund method

has been considered in this text. This method provides for setting aside each year such a sum, invested at a rate of interest and compounded either annually or semi-annually, as will produce at the end of an estimated period an amount equal to the original investment. (See Table 17, Chapter X.)

Two influences are at work creating the need for this fund. The first is:

97. Physical Deterioration. — From the moment a steam plant is put into service, it begins to wear out. This is evidenced by the wearing of bearings and of turbine blading, the slagging of furnace walls and the erosion of fans. It proceeds at a different rate for different classes of equipment. The composite of all these rates is the rate for the plant as a whole. The estimated useful life of various kinds of equipment usually installed in a steam power plant is given in Table 11.

This wearing process can, in some cases, be retarded and in others completely arrested by the spending of sufficient money for maintenance and repairs. It may be safely said that a power plant will never wear out if enough money is spent on maintenance and replacements. However, the time may arrive when the money spent on such maintenance and replacements will pay the fixed charges on new equipment to replace the old, and the old equipment may then be said to have reached the end of its useful life. (See also Chapter X, Section 144.)

98. Obsolescence. — The second of these influences is obsolescence. Obsolescence is the loss in value or in economic usefulness brought about by engineering developments, by an increase of scientific knowledge or by perfection of methods. This is illustrated by the case which follows. A certain steam plant was built in 1918. In 1918 ~~1927,~~ with the current prices of coal and labor, it had a production cost of 8½ mills per kwhr. The steam pressure was 225 lb, and the boilers, turbines and fuel burning equipment represented the best engineering thought and design when the plant was built. But by 1927 advancement had been so rapid in power station equipment, engineering and design that a new plant of the same capacity, representing no larger investment, could be built to produce energy, operating at the same capacity factor, at an average cost of 4 mills. The difference between the two costs, 4½ mills per kwhr, was sufficient to pay the annual fixed charges on the new plant, with some margin. The first plant was obsolete, though only nine years old.

TABLE 11

USEFUL LIFE EXPECTANCY OF THE PRINCIPAL PARTS OF A STEAM POWER PLANT

Description	Probable Life — Years
Accumulators	15
Boilers — water tube	20
Boiler accessories	20
Breechings — steel	10–30
Buildings	
Brick	30
Wood or wood frame	20
Cables and feeders	15–25
Coal and ash machinery	20
Compressors — air	20
Condensers	20
Cranes	30
Economizers and air preheaters	15
Electric generators	20
Electric motors	20
Engines — small steam	15
Steam turbines	20
Fences	12
Foundations	Same as life of equipment supported
Fuel oil handling equipment	20
Furniture and fixtures	15
F. W. Heaters	20
Pipe and pipe covering	15–25
Pumps — reciprocating	15–20
Pumps — centrifugal	20
Stacks — brick or concrete	30
Steel	12–15
Stokers and other fuel burning equipment	20
Superheaters	20
Switchboards and switchboard equipment	20
Tools and shop machinery	15
Transformers	15

Obsolescence may creep slowly on a plant or advance rapidly. This applies particularly to various parts of the plant. An example, outside the power plant field, may be used to illustrate this statement. Comparison of automobiles from year to year ordinarily shows little real difference between them. Compare, however, a new car with a car five years old. The great change is

at once apparent. On the other hand, the adoption of the four wheel brake made cars with brakes on only two wheels obsolete almost over night.

Another form which obsolescence takes is inadequacy. Plants and equipment become inadequate when they are no longer able to meet the load requirement and it becomes necessary to substitute larger and more efficient units. In many power plants, for instance, growing load has necessitated frequent extensions of plant. Perhaps the electrical equipment — oil switches, buses and the like — though still serviceable, are inadequate and will not handle the load imposed on them, and new and larger ones must be substituted. Or, for example, the boiler plant has been extended. The existing boiler feed pumps will serve only a part of the plant. They are of the reciprocating type. By substituting a new and more efficient centrifugal pump, both obsolescence and inadequacy are recognized. (See also Chapter X, Section 145.)

99. Obsolescence from Without. — A power plant may also become obsolete from influences other than those acting within the plant. Being only one part of a unified whole, it is subject to the same competitive conditions as those to which the business it serves is subject. For instance, a public utility selling power to industrial companies finds that it cannot compete against new private plants which industry can build. The utility plants are old and inefficient, and it must either lose the business or take it at a loss if the present equipment is continued in service. The alternative is to install new equipment, thus rendering the old obsolete. If proper provision has been made by the utility company for obsolescence, this can be done without any hardship.

In another case a manufacturer finds it necessary to reduce the costs of his product to meet competition. This may mean a change in manufacturing processes. Perhaps more power is required and less steam, or the steam requirements are doubled. This requires changes and additions to the existing power plant thus rendering obsolete those parts to which the changes must be made.

The time when a power plant will become obsolete cannot be predicted. Perhaps the effect of obsolescence and its cost can be anticipated in a degree by an arrangement of equipment and flexibility in design, so that rehabilitation at a later date may be relatively simple. And yet obsolescence has been more in-

fluential than any other factor in causing supersession of old plants by new. Advances in the art of power generation have been so rapid that power plants seldom have had the opportunity to wear out. Therefore, although obsolescence cannot be anticipated, the engineer must take cognizance of the fact that plants seldom wear out but become obsolete, and estimate a rate of depreciation in the fixed charges, one not entirely based on the functional life of the apparatus and plant, but one which, from experience, company records or other sources, will reflect the expected life of the plant, regardless of the forces causing it to be no longer useful.

100. Rates for Fixed Charges. — In this text, wherever calculations using fixed charges have been made, a rate to be applied to the overall investment in steam power plants of $13\frac{1}{2}$ per cent, made up as follows, has been assumed:

Cost of money	7 per cent
Taxes and insurance	2 "
Depreciation	4.5 "

The rate of 7 per cent for cost of money should not be confused with interest on invested capital. If the plant is built partly with borrowed money and partly with owner's money, the rate as previously explained must reflect the income requirements both of the lender of the capital and of the owner, and is a composite of both these demands.

The rate for taxes and insurance does not reflect the cost of these items in any one community, but has been assumed to be relatively close, to represent the average of many situations.

The depreciation rate is based on an expected plant life of between 15 and 16 years. From Table 17, Chapter X, it will be seen that if $4\frac{1}{2}$ per cent of the total investment is laid aside annually and allowed to accumulate for a period of between 15 and 16 years, with an interest rate of 5 per cent compounded annually, the resulting sum will equal in amount the original investment.

The interest rate of 5 per cent used in determining the depreciation charge is preferred by the authors in their work. Since in many cases the depreciation fund is re-invested by the owners in the business, it is often contended that the annual contribution for depreciation should be compounded annually by a rate of interest equal to the rate earned by the business. If earnings

were always at a uniform rate or if they could be predicted with any certainty over the expected life term of the plant, there might be some merit in such an argument. However, it is seldom possible to ascertain the probable earnings of a business from year to year over any considerable period of time, so that, to be conservative, the 5 per cent rate is used.

101. Fixed Charges on Optional Investment. — The rate of $13\frac{1}{2}$ per cent is the fixed charge against the plant as a whole. It cannot be disputed that some parts of the plant do not participate directly in producing earning power, but must be provided for the conduct of operations, and that, therefore, other parts must yield a higher rate. This is true of what might be termed "optional" or "increment" investment made to promote efficiency in burning coal or saving labor or for any other purpose, to lower production costs.

Investment of this type must carry a higher burden of fixed charges in order to maintain the average. The amount of the increase over the average rate will depend on the nature of the extension, expected life, future prospects of growth in the business and many other factors, so that a formula for a general rate of fixed charge on "optional" investment cannot be laid down, but must be determined in each individual case.

102. Production Costs. — Steam plant production costs are usually subdivided as follows:

Fuel cost.
Supervision and labor cost.
Total maintenance cost.
Miscellaneous supplies and expense cost.

Fuel Cost. — Of these, fuel cost is by far the largest. It will amount to 60 to 75 per cent of the total cost of production, depending on the load factor, plant efficiency and cost of fuel delivered to the plant. It is the controlling factor in the selection of equipment and design of plant. Kinds of fuels and the economical selection of the proper fuel have been discussed in Chapter III. In Chapter III, Section 38, it is shown how the costs of coal and oil have varied from year to year. There has also been a tremendous decrease in the use of fuel per unit of energy produced, as shown in Table 12.

Supervision and Labor Costs. — The second largest item of expense in the production of power is the labor cost. It will vary

TABLE 12

TOTAL FUEL GENERATED ENERGY, COAL CONSUMPTION AND ECONOMY IN PUBLIC UTILITY POWER PLANTS*

Year	Energy Generated in All Public Utility Plants, Million kwhr	Coal Equivalent of All Fuel, Millions of Tons	Pounds of Coal per kwhr
1919	38,921	38.88	3.2
1920	43,555	41.43	3.0
1921	40,976	35.25	2.7
1922	47,659	38.01	2.5
1923	55,674	43.53	2.4
1924	59,014	43.14	2.2
1925	65,870	44.79	2.1
1926	73,791	45.86	1.95
1927	80,205	45.91	1.84
1928	87,850	46.39	1.76
1929	97,352	52.57	1.69
1930	95,936	50.65	1.62
1931	91,729	47.13	1.55
1932	84,045	38.29	1.51

* From U. S. Geological Survey data published in Jan. 7, 1933, issue of the Electrical World.

over a wide range, from 10 per cent to 25 per cent of the total production cost, depending on plant design, management policy and plant capacity factor. Much study has been given to the problem of reducing labor costs in power stations in recent years. Plant design and layout have a tremendous influence on the number of employees required to operate it. In Table 13 is shown the number of employees, classified according to their duties, required to operate several typical large power plants containing two generating units. Variation of the number of boiler units required for a given plant capacity should be noted, and also how this variation affects the number of men required to operate them.

The number of employees required for plant supervision is largely a matter of management policy and organization. At some plants, a complete technical and supervisory staff is maintained. At others this supervision may be from a central office from which a number of other plants may also be supervised. The cost of operating this office is charged against the plants supervised in proportion to the time of the employees spent on

TABLE 13

EMPLOYEES REQUIRED IN ELEVEN TYPICAL TWO UNIT STEAM ELECTRIC POWER PLANTS

Plant	A	B	C	D	E	F	G	H	I	J	K
Plant capacity, kw	40,000	50,000	80,000	100,000	80,000	60,000	70,000	70,000	70,000	100,000	90,000
No. of generating units	2	2	2	2	2	2	2	2	2	2	2
No. of boilers	4	6	8	8	8	6	4	6	6	6	8
Fuel burning equipment	Stokers	Stokers	Stokers	Stokers	Stokers	Stokers	Pulv. Coal	Pulv. Coal	Pulv. Coal	Pulv. Coal	Pulv. Coal
Supervisory employees	11	17	40	42	38	12	18	21	13	29	36
Turbine room employees	9	12	10	22	17	10	16	12	26	18	23
Boiler room employees	14	24	32	43	53	23	40	47	47	45	50
Electrical operating employees	9	9	12	16	17	6	8	13	9	10	14
Maintenance employees	9	15	67	55	54	13	25	47	41	50	48
Total plant employees	52	77	161	178	179	64	107	140	136	152	171

each plant, and though this is not indicated by the number of employees, it does show in the cost of production. Maintenance crews are often organized in the same manner. In large systems each plant has only a small crew of maintenance men, and the major repairs are made by men from a central organization.

Total Maintenance Costs. — To this account is charged the cost of all repairs to buildings and equipment which in no way change the identity of the part repaired. It will amount to 10 to 15 per cent of the total cost of production. If the plant is poorly laid out, with equipment crowded, and if the equipment is not well selected and substantially built, this cost will represent a higher proportion of total production costs than if the reverse were true. Maintenance costs are a factor not to be overlooked in the selection of plant equipment, particularly in the selection of auxiliary apparatus.

Supplies and Expense Cost. — This cost is usually a very small portion of the total, is little influenced by design of plant and varies largely with the management policy.

103. Power Cost Analysis. — For economic studies of various kinds, where comparisons of production expense are necessary, it is desirable to know how these production expenses behave under the varying influences of station output and capacity factor. To compare the average cost of production, unless these factors are the same, is an incorrect procedure and one which will lead to unsatisfactory conclusions.

Annual production expense formulae have been developed in several forms which correct for the variation in the several operating factors and allow the making of production expense comparisons. All are based on the Hopkinson[1] theory that, for any operation dealing with costs, those costs can be divided into two parts, one part which is constant regardless of the extent of use of the facilities, and the other part which varies in magnitude with the use.

One method is to assign empirically to the fixed cost portion of the formula and to the variable portion a percentage of each item of production expense. See Table 14.

For preliminary approximations of cost, this method gives fairly satisfactory results. It is far from being precise, however, and in most cases more careful analysis must be made.

[1] Dr. John Hopkinson, presidential address to Junior Engineering Society (British) 1892, reprinted in "Rate Research," Vol. 2, 1912, pages 23-38.

TABLE 14

DIVISION OF PRODUCTION COST* BY PERCENTAGES

	Fixed Cost, Per Cent	Variable Cost, Per Cent
Operation		
Superintendence.	70	30
Boiler labor....	60	40
Engine labor....	100	0
Electric labor...	70	30
Other labor.....	70	30
Fuel...........	15	85
Sale of ashes..............................	15	85
Water....................................	25	75
Lubricants................................	70	30
Boiler plant supplies........................	55	45
Boiler plant expenses........................	55	45
Other power plant supplies..................	55	45
Other power plant expenses..................	55	45
Superintendent's and other employees' expenses.	70	30
Maintenance		
Power plant structures.......................	100	0
Railroad sidings and trestles.................	50	50
Boiler plant equipment......................	55	45
Steam engines and turbines..................	55	45
Turbo-generators..........................	55	45
Other electric generators.....................	80	20
Other electric equipment.....................	80	20
Coal storage and weighing equipment..........	50	50
Other power plant equipment.................	55	45

* Classification according to the accounting system prescribed by the Public Service Commission of the Commonwealth of Pennsylvania.

Another method[2] is to draw a graph on which the production costs for a station in dollars for any given output are plotted as ordinates, and the outputs as abscissae, and if there is a sufficient number of points to give some range between them, a curve as shown in Fig. 23 can be developed. The intercept of this curve on the zero ordinate is a constant cost in dollars per year, and the tangent to the slope of the curve is a variable cost depending on the kilowatt-hours output. The equation for this curve is one of the first degree which may be written $A = K + K_3 \times \text{kwhr}$,

[2] This method of cost allocation closely follows one devised by N. E. Funk for the Philadelphia Electric Company.

in which the total annual cost A is equal to K, a constant cost in dollars per year, plus a constant cost K_3 in mills per kwhr multiplied by the kilowatt-hour output.

If plants were all the same size and operated at all times to produce the full capacity installed, and if fuel costs were constant, then this formula would satisfy all needs for determining annual plant costs for comparative purposes.

However, it has been found that the magnitude of K is affected

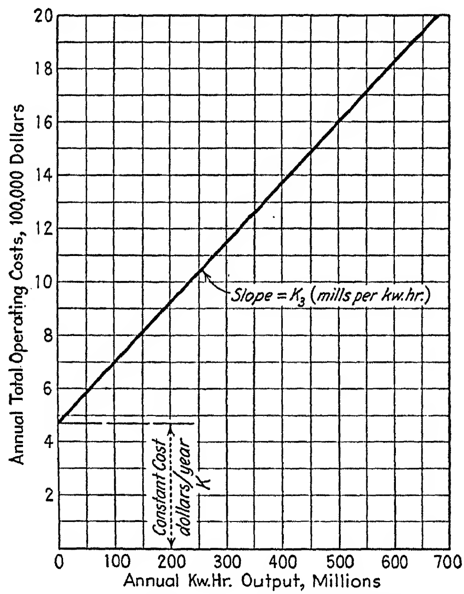


FIG. 23. Curve showing method of dividing operating costs, in a plant of approximately 100,000 kw capacity, into fixed and variable components. (K = \$470,000 per year and K_3 = \$0.00223 per kwhr.)

by the capacity of the plant, the number of units installed and the ratio of the peak load carried to the installed capacity.

It is, therefore, necessary in many cases that K be further divided into components K_1 and K_2, K_1 representing that part of the cost determined by capacity and K_2 that part determined by peak carried or prepared for, the formula becoming: Total annual cost $A = K_1 + K_2 + (K_3 \times \text{kwhr})$. To each of these constants, a portion of each element of operating expense is assigned; for some costs the allocation must be made empirically, and for others it can be determined by mathematical analysis.

To make this allocation, it is necessary to start with certain assumptions as to operating conditions in the plant, beginning with a cold plant condition and progressing to a plant in full operation.

For K_1 the plant is assumed to have boilers fired sufficiently for heating, for running boiler feed pumps and service pumps and with all steam lines and electrical equipment ready for service.

For K_2 the additional condition is assumed of having one main unit running but not generating, with its necessary auxiliaries, and enough boilers under fire to carry an expected peak.

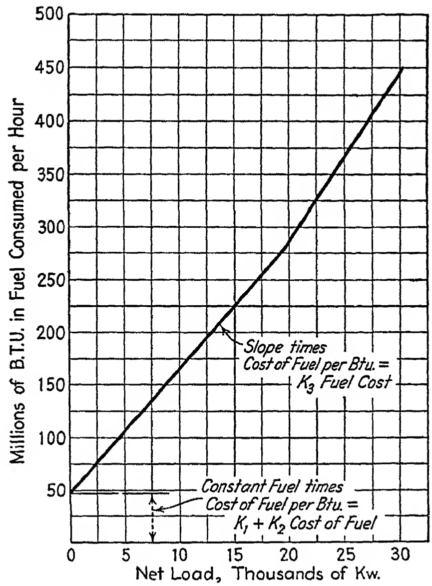


FIG. 24. Curve showing the division of the fuel consumption into fixed and variable elements.

For K_3 the final condition is assumed of the plant carrying the expected load and producing energy.

Each assumption is a step in advance in the operating cycle of the previous one and costs are allocated to each on this basis, that is, costs allocated to K_2 are additional costs not previously allocated to K_1, and costs allocated to K_3 are additional costs not previously allocated to K_2.

Fuel Cost Allocation. — From records or test data or from guarantee data, the generally used station Btu input versus kwhr output curve is plotted as in Fig. 24. This curve can be de-

veloped on an hourly, monthly or annual basis. The constant portion represented by the intercept of the curve on the zero ordinate must be divided between the constants K_1 and K_2. To K_3 is assigned the value represented by the tangent to the slope of the curve. To K_2 is allocated a part of the constant fuel value equal to the fuel required to generate the no-load steam requirements of the turbine or turbines which are in operation to carry the expected peak and the steam required for the auxiliaries.

The balance of the constant fuel cost is allocated to K_1.

The values obtained are in Btu and must be multiplied by the cost of the Btu's in the particular fuels in use.

Supervision and Labor Cost Allocations. — Labor costs are distributed as follows:

To K_1 — all of superintendence and of operating labor that is required for the care and protection of the property and for firing boiler for the heating and pump requirements as defined for this condition.

To K_2 — the additional supervision costs of men in control positions such as chemists and test engineers, and operating labor for the additional equipment in service.

To K_3 — usually there should not be any labor charge to this constant, although in certain stations total output may influence the number of operating men required. Where such is the case, this part of the labor cost is assigned to K_3.

Maintenance Cost Allocation. — For the analysis and distribution of this cost, it is desirable to have a record of it over as wide a range of station loads and for as many years as possible.

To K_1 are assigned all maintenance costs incurred in maintaining the equipment and plant in good physical condition without use, in detail: probably all the usual costs of maintenance buildings and grounds, other electric equipment and the no-load maintenance on equipment in use as defined for the K_1 assumption.

The allocation of the remaining cost to K_2 and K_3 is somewhat more difficult. Unusual costs, such as turbine wrecks, boiler failures and other non-recurring items of heavy expense, should be prorated over the entire period for which data are available. Since these items are in no way caused by the K_1 condition, they can be charged only to K_2 and K_3. Therefore, to obtain the K_2 and K_3 costs, the total maintenance costs, with K_1 deducted, should be plotted as a curve with dollars cost as ordinates and

TABLE 15

ANALYSIS OF PRODUCTION COSTS OF NINE TYPICAL POWER STATIONS

	A	B	C	D	E	F	G	H	I
Capacity, kw	60,000	120,000	100,000	188,000	70,000	180,000	70,000	28,000	21,000
No. of units	1	2	2	5	2	6	3	2	1
K_1+K_2 cost per kw capacity	$2.30	$4.46	$4.00	$4.51	$3.96	$4.16	$11.44	$8.90	$8.20
K_3 cost, mills per kwhr	1.75	2.45	2.50	3.34	2.75	2.91	4.12	2.28	1.58
Coal cost per net ton	$4.00	$4.30	$2.25	$4.85	$4.00	$4.35	$2.25	$2.00	$1.90
Btu per lb in coal (avg.)	14,000	13,800	10,500	13,800	14,000	13,800	10,800	10,800	10,800
Year built	1929	1926	1927	1924 to 1927*	1925	1922	1918 to 1920*	1923	1926

* Additions to original station.

kilowatt-hour output for each year or period for which data are available as abscissae. The intercept of the curve on the zero ordinate is the K_2 cost, and the slope of the curve represents the K_3 cost.

Supplies and Expense Cost Allocation. — Practically all this expense should be assigned to K_1. This will include cost of essential services, such as lighting, water, communication and expenses of the supervisory forces.

Some part of these costs may be assignable to K_2 and K_3, depending on the nature of the operation, such as transportation costs of the additional men required to operate the plant, supplies for the chemical laboratory, supplies for feed water treatment, gauge charts and other minor costs.

The K_1 and K_2 costs are functions, respectively, of the capacity of the plant and the peak carried or expected. By dividing the costs determined for each of the two constants by the kilowatt value of the capacity and peak, the formula may be restated: $A = K_1 \times$ (station capacity) $+ K_2 \times$ (peak prepared for) $+ K_3 \times$ (kwhr generated).

This method of cost analysis outlined herein, although particularly designed for plants which have been in operation long enough to provide cost data, can be used for new plants also. In a new or a projected plant, it is possible to determine fuel costs from design and equipment guarantee data. The other costs may be estimated from experienced costs in other plants with similar equipment, and the constants built up on that basis.

Constructed on a rational basis, with its freedom from complicated mathematical calculations, this method of preparing a formula for power production cost analysis has been found by the authors to be most satisfactory and productive of the desired results. Some typical station costs analyzed in this manner are shown in Table 15.

The reader is referred for detailed information on the preparation of the plant fuel performance curve to the N. E. L. A. Prime Movers Committee report No. 278–101, Power Station Betterment, September, 1928.

CHAPTER VII

GENERAL FACTORS CONTROLLING THE ECONOMIC UTILIZATION OF WATER POWER

104. Water Supply.—An adequate supply of water, with some difference in head, is a prerequisite for the construction of a hydro electric plant,[1] and streams with a large annual discharge and some gradient are usually potential sources of power. The distribution of the flow of the stream throughout the year is important. A stream might have a fall of several hundred feet to the mile and an ample annual run-off, but the flow might be so distributed that at certain seasons of the year the stream bed was practically dry, while at other seasons of the year it was a raging torrent. Manifestly, such a stream would not ordinarily be a promising source of power unless this unfavorable condition were overbalanced by the existence of favorable reservoir sites making it feasible to regulate the flow to some extent through the year. An even distribution of rainfall throughout the year helps in producing a fairly steady stream discharge.

The character of the soil cover of a watershed is important as affecting distribution of run-off. A steep rocky watershed, or one covered with impervious clay soils, will have a relatively quick run-off and will be apt to have a poor distribution of run-off throughout the year. On the other hand, a watershed covered with a deep deposit of sands and gravels is like a sponge. It soaks up the rainfall and permits it to percolate out at a fairly even rate. Such deposits are in effect huge underground reservoirs. Because of the extensive deep deposits of glacial sand and gravel, some of the rivers of southern Michigan have a flow so steady that the maximum discharge is only about twice the minimum.

A stream whose discharge is practically uniform throughout the year is an ideal prospect for power purposes as far as water supply is concerned. Streams whose headwaters abound in natural lakes and swamps, or whose flow is controlled by reser-

[1] The pumped storage hydro electric plant is an exception. See Chapter XII, Section 169.

voirs, measurably approach this condition. Rivers whose drainage areas contain a large percentage of lake area, such as the Niagara, the St. Lawrence and some of the rivers of the Adirondacks, have a relatively steady flow.

Although a steady stream flow is a highly desirable characteristic for a river which may be utilized for the production of power, other advantages which a stream may possess may more than counterbalance the lack of a reasonably steady flow. Thus, there are rivers where the maximum flow is a thousand times the minimum, but where the development of power even without storage has proved highly profitable.

The quantity of stream flow also has an important bearing on the economics of a hydro electric project. A territory having a rainfall of 100 in. per year will, other things being equal, be more abundant in water power resources than a territory having a rainfall of 5 in. per year. A river whose watershed yields an average of 3 sec-ft per square mile will, other things being equal, be a more promising source of power than one which yields only 1 sec-ft per square mile.

Water supply is one of the important factors bearing on the economics of any proposed hydro electric project and should be one of the first to be investigated; but it is not within the province of the present work to cover the investigation and determination of stream flow, and the engineer charged with the investigation of water supply for any proposed hydro electric project is referred to the various works on hydrology, water power and water supply.[2] Various governmental bureaus, including the U. S. Geological Survey, have also published much material on the subject, including records of flow on most of the principal rivers.

105. Topography. — As power available is determined by the product of the quantity of water flowing in unit time and the head through which it passes, topographical conditions in any territory have an important bearing on the feasibility of proposed hydro electric projects. Well watered mountainous sections usually afford excellent possibilities for the development of hydro electric power. On the other hand, a delta plane seldom if ever presents any possibility for the economic development of such power.

[2] Such as the following: "River Discharge" by John C. Hoyt and Nathan C. Grover (John Wiley & Sons), "Hydrology" by Daniel W. Mead (McGraw-Hill Book Co.), "Elements of Hydrology" by A. F. Meyer (John Wiley & Sons), "Water Power Engineering" by H. K. Barrows (McGraw-Hill Book Co.) and "Hydro Electric Handbook" by Creager and Justin (John Wiley & Sons).

Streams with steep gradients, however, are not necessarily any less costly to develop for power purposes than streams of relatively moderate gradient. Rivers having a gradient of six feet per mile or less often present excellent opportunities for the development of power, and frequently have the further advantage that the dam which creates the head also creates an appreciable amount of storage.

Topographical conditions have a very marked effect on the cost of dams at various sites and frequently dictate the selection of dam sites. Thus, a location on a river where the hills on each side approach close to the river bank usually presents favorable topographical conditions for the location of a dam. If, in addition, the hills upstream from the proposed location recede to some distance from the river banks, then topographical conditions may be considered favorable for the location of a reservoir basin provided the slope of the stream is not so great as to require an excessive height of dam.

Topographical conditions also affect in a very marked degree the run-off of a watershed, the rapidity of run-off and its distribution as well. Thus, other factors being the same, a stream having a steep, rugged watershed will have a greater annual run-off than a stream with wide valleys and flat slopes. Also, the stream with the steep, rugged watershed will be more subject to severe floods.

Extensive topographical surveys and the preparation of topographical maps are prerequisites for the investigation of any proposed hydro electric project.[3] Topographic maps, such as those of the U. S. Geological Survey, which are sufficiently precise for reconnaissance investigations, are available over large territories in this and other countries.

106. Geology. — Geological conditions have a marked effect on the feasibility of hydro electric projects, and thorough and frequently expensive subsurface investigations are required in connection with all projects.[4]

[3] See "Water Power Engineering," Chapter IX, by Daniel W. Mead (McGraw-Hill Book Co.), "Hydrology" by Daniel W. Mead (McGraw-Hill Book Co.), "Earth Dam Projects," Sections 40 to 50, inclusive, by Joel D. Justin (John Wiley & Sons).

[4] See "Water Power Engineering" by H. K. Barrows, pages 264 to 272 inclusive (McGraw-Hill Book Co.), "Hydrology" by Daniel W. Mead, Sections 181 and 182 (McGraw-Hill Book Co.), "Earth Dam Projects" by Joel D. Justin, Chapter III (John Wiley & Sons).

From the standpoint of topography only, a dam site may appear to be extremely favorable, but the geological conditions may be such as to make the erection of a dam at the proposed site hazardous or extremely expensive.

Thus, in several instances within the experience of the authors, dam sites have been tentatively located in accordance with topographical considerations at sites where the valley narrowed up until the high hills were very close together, only to have the borings reveal the fact that although on one of the hills satisfactory ledge rock was located at no great depth below the surface, the ledge dipped downwards and at about the center of the stream bed was at a very great depth, and that the other hill was a very pervious glacial deposit of gravel extending to a depth of several hundred feet below the river bed before the elusive ledge rock was encountered.

On one river which had an abundance of dam sites which appeared extremely favorable from a topographical standpoint, all of them were proved to be economically undesirable because of the unfavorable geological conditions. As the result of extensive subsurface investigations, the most practicable dam site was finally located at a point where the geological conditions were favorable, but where topographical conditions gave no indication whatever of the existence of a favorable dam site.

In another instance a dam site was located in a narrow rock gorge where ledge rock was exposed on both sides and in the bed of the stream. All surface indications appeared extremely favorable, and it seemed that money spent for geological investigations at a site like this would be wasted. However, a few shallow diamond drill borings were put down which appeared to confirm the surface indications, and accordingly construction was started. During the excavation for the foundation, it was found that the supposed ledge in the stream bed was really a series of huge boulders. Consequently, extensive diamond drill borings were then made after it was too late to select another site. This more extensive subsurface investigation led to some startling discoveries. The true ledge at the bottom of the gorge was more than 100 ft below the bed of the stream. One of the rock walls proved to be native ledge, and all the rock at the site was of igneous or metamorphic origin, but the other rock wall of the gorge was not native ledge at all, but a broken-off ledge turned upside down.

In a previous geologic era, this rock ledge wall had towered to a much greater height, but the top had been broken off and fallen down into the bottom of the gorge and against one wall of the gorge. The result was a formation abounding in large cavities. Grouting operations of an unusual and extensive nature, as well as upstream blanketing, were required before the site could be considered safe.

Large cavities and underground water channels are characteristics of certain limestone formations, and such conditions require careful investigation and analysis before decisions as to the economic and physical feasibility of a project can be determined. In some cases where the dam site itself has not been affected, the existence of such formations in the reservoir basin or pond has seriously affected and sometimes destroyed the economic value of the project.

The geological conditions on a watershed have a marked effect on the character of the stream flow which a hydro electric project utilizes. Thus, a dam and reservoir may be located in an impervious formation, but a large part of the watershed above may consist of a limestone formation with many caverns and underground water courses. Such a condition may be either favorable or unfavorable. It is favorable and tends to cause a better distribution of the run-off if there is no escape of water from the watershed. On the other hand, if the cavernous limestone formation is so located that it conducts the water beyond the divides into another watershed, it is extremely unfavorable and the total annual stream flow may prove to be seriously affected.

If the watershed has a heavy soil cover of sandy, gravelly, glacial drift, this condition will help to produce a relatively even distribution of run-off throughout the year. On the other hand, a watershed largely bare of soil cover, or one covered with impervious clay soil, will produce a quick run-off and stream flow will tend to be flashy and poorly distributed throughout the year.

107. Property Values. — Property values have an important bearing on the economic feasibility of hydro electric projects. Many physically favorable sites for hydro electric projects in the more thickly settled portions of the country are not economical to develop because of the tremendous value of the real estate which would be flooded. For instance, just above Harrisburg, Pa., the Susquehanna River passes through a gap in the

mountains which would form an excellent site for a high masonry dam and power development. The dam would create a great lake which would not only furnish storage for the power project at the site, but would also regulate the flow of this rather flashy river for the benefit of projects downstream having a present installation of nearly a half million kilowatts and thus increase the value of these developments also.

If the valley were undeveloped, such a project would be very promising. However, it would flood out many miles of the main line of the Pennsylvania Railroad, as well as other railroads, and would destroy several cities and towns. The property damage involved would be so huge that the project is not entitled to any serious consideration.

The usual cost for real estate acquired in connection with existing successful hydro electric developments is from 10 to 35 per cent of the total cost of the development. An unusually high cost of real estate is not always a good reason for turning down a proposed hydro electric project, because there may be compensating advantages in location or in a relatively low cost of construction for some of the various structures of the project.

Real estate for hydro electric projects can seldom be obtained at anywhere near prevailing market prices, even though the company undertaking the project is protected by the power of condemnation. Prices actually paid usually average at least twice the market price for real estate in the section where the project is located.

108. Centers of Population and Load. — The location of a hydro electric project in reference to centers of population and load has a very important bearing on its economic feasibility. The character of the population, as well as its size, has an important bearing on present and prospective load requirements. A large city having miscellaneous commercial and industrial pursuits may require a total central station installation of, say, 0.3 kw per capita. A smaller industrial city, in which heavy industries using central station power are an important factor, may require a central station capacity of 0.5 kw to 1.0 kw or more per capita. On the other hand, a commercial town (or "farming center") may require only 0.1 kw of installation per capita. These figures are more or less typical for towns and cities in the United States and Canada. Throughout the civilized world,

there is a wide variation in the requirements for central station power. Thus, a large city in Brazil may require only 3/100 kw of installation per capita.

Table 2, Chapter I, gives total central station installations and installation per capita for each of the states of the United States. The average for the whole country is shown to be 0.26 kw per capita, and the highest per capita installation is 0.58 kw in Montana. Table 1, Chapter I, gives similar data for certain foreign countries.

In this matter of location, hydro electric plants are frequently at a distinct disadvantage as compared to steam plants. A steam plant may be located almost anywhere, where a sufficient supply of water for condensing purposes and suitable transportation facilities for the delivery of fuel are available. Furthermore, as most of the large cities are located on rivers, lakes or harbors, it is frequently feasible and economical to locate steam plants close to the center of gravity of the load which they serve.

Recently, however, economic considerations have led to the construction of great steam plants utilizing units of tremendous capacity. The capacity of some of these plants is so great that very few individual load centers are big enough to require them. Consequently, the present tendency is to utilize such supersteam plants as a part of a territorial power system, and they are frequently located somewhat remotely from any individual load center, but suitably for obtaining their condensing water and fuel supply. Such plants, although frequently located near the center of gravity of the total load served, must reach the individual load centers by means of transmission lines and have thus lost some of the advantages enjoyed by the steam plants located at the load centers.

A hydro electric plant, on the other hand, must be located where stream flow, head, topography and geological conditions are sufficiently favorable. Although there are notable exceptions, suitable sites for hydro electric development are not apt to be found at important centers of population. Such sites are much more likely to be found among the mountains far from centers of population. Many of the finest sites remain undeveloped because they are so remote from centers of population that it would be impracticable or uneconomical to transmit their power over the great distances that would be involved. The closer a proposed hydro electric project is to centers of load and

population, the more likely it is to prove economically feasible, other conditions remaining the same.

109. Size of Project. — The size of the project as compared to the size of the load to which it is proposed to connect it has an important bearing on the economic feasibility of a proposed hydro electric project. The physical features and stream flow conditions at the site control, to a considerable extent, the size of any proposed development.

There may be a great river near a prosperous load center having a total load of, say, 20,000 kw. The river, we will say, has a fall of 8 ft to the mile. At the site the river is nearly a mile wide, and to build even a 40 ft dam across it at the site would cost $15,000,000. Even if it were feasible to make the installation at the hydro project equal to the load (giving a total cost for the project of, say, $16,000,000), the cost per kilowatt of installation would be $800. This is a figure so ridiculously high that it is certain that the load can be supplied more cheaply by other means. On the other hand, if the load to which the proposed project might be connected were 500,000 kw instead of 20,000, it might be feasible to install a plant of 100,000 kw at the site, and the resulting cost might then be only $210 per kw. At this figure the proposed hydro plant might be economically advisable and form a desirable source for a part of the system's power requirements.

The unfavorable relation of the size of proposed project to connected load is one of the main reasons why such great potential power sources as the St. Lawrence and the Columbia have remained practically undeveloped to the present time.

110. Price of Fuel. — The cost of fuel in any given territory has an important bearing on the economic feasibility of any proposed hydro electric project. By many who have not gone into the subject deeply, the cost of fuel is considered an almost all important factor determining the economic feasibility of proposed hydro electric projects. However, fuel is never free, and, as will be shown later,[5] even in districts where it is extremely cheap it will usually be found economical to serve a part of the load with hydro electric power if favorable hydro sites are available.

On the other hand, the importance of fuel cost should not be underestimated, as even in a section abounding in favorable sites

[5] See Chapter XI, Section 162.

for hydro electric development, it may prove economical to supply only a relatively small percentage of the total load from hydro electric plants if fuel is sufficiently cheap. The other extreme is reached in such sections as the provinces of Ontario and Quebec, where fuel is relatively expensive and where favorable hydro sites are numerous. As a result, the power requirements of these provinces are met almost entirely by hydro electric power, as shown by Table 1.

CHAPTER VIII

INTERNAL ECONOMICS OF HYDRO ELECTRIC PLANTS

111. Simplicity of Hydro Electric Plants. — As compared to the steam plant, the hydro plant is relatively simple. The pressure and / or velocity of the moving water act on the vanes of the turbine or wheel, causing it to revolve, and the wheel is usually direct connected to the electrical generator and exciter. The necessary auxiliaries, consisting of the mechanism for operating gates and valves and governor, are also relatively simple.

Hydraulic turbines revolve at relatively low speeds, usually from 70 to 200 revolutions per minute, although impulse wheels revolve at speeds sometimes exceeding 300 rpm. These low speeds contrast with speeds of 1200 to 3600 rpm for steam turbines. The slow speeds and relative lack of auxiliaries for hydro electric plants produce slow physical depreciation and low costs for maintenance, repairs and attendance. This simplicity also makes for a somewhat higher degree of reliability. Statistics for a large number of units collected by the National Electric Light Association[1] show that the average hydro electric unit had a service demand availability factor of 99.55 per cent, as compared to 96.01 per cent for steam driven units. The service demand availability factor is the ratio of the number of hours the unit was actually operated to the number of hours that it should have been operated.

112. Status of Development of Hydro Electric Plants. — When hydraulic turbines were first applied to driving electrical generators, turbine efficiencies were relatively low. Since then improvement has been steady, as indicated by Fig. 25, and present day designs leave little room for further advance as far as efficiency is concerned. Efficiencies of 88 per cent are common; 90 per cent is frequently exceeded, and efficiencies of 92 and 94 per cent have been attained. Current progress is towards

[1] See page 4 of "Report on Mechanical Reliability of Hydro Electric Units," 1930, Hydraulic Power Committee, Engineering National Section, National Electric Light Association.

further simplification and higher speeds, which in turn produce lower costs.

It is a mistake, however, to assume that hydro electric plants have reached the zenith of their development, and that no further progress is practicable. As far as efficiency is concerned, the assumption is measurably correct, but in other directions much progress is being made, and there is still room for a great deal more. Designs are being simplified. New and higher speed wheels are being developed, thus permitting the development of more power in a given space and greatly reducing the cost of equipment and structures required. For instance, a 50 ft head

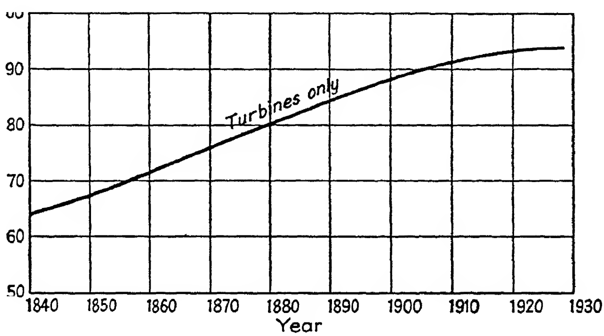


FIG. 25. Growth in the efficiency of the hydraulic turbine. (From page 24, Statistical Supplement to Electric Light and Power Industry in the United States, National Electric Light Association, Jan. 1, 1931.)

plant of today, having a capacity of 50,000 kw, may not occupy any more space or require any more structural materials, concrete, steel, brick, etc., than a plant of 10,000 kw capacity of the vintage of 1912.

Furthermore, because the incremental cost of hydro capacity is very low[2] the present tendency is to put in installations of much larger capacity in plants which form a part of a large system, than was the practice only a few years ago.

113. Types of Hydro Units and Their Application. — Modern water wheels or turbines develop power by means of water pressure, velocity of the water or a combination of these two factors. The Pelton (Fig. 26) or impulse wheel utilizes the velocity of the water impinging on its buckets for producing

[2] See also Chapter X, Sections 151 to 154 inclusive.

power. The Francis (Fig. 27) or reaction runner uses both pressure and velocity. The more recent propeller type wheel, of which the Nagler and the Kaplan (Figs. 28, 29 and 30) are examples, also use both pressure and velocity. Impulse wheels are economically applicable to heads of 850 to 3000 ft; Francis runners may be used for any heads from 10 ft to 1000 ft, but at heads from 10 to 60 ft the propeller type of runner is usually more economical, because of higher speed and consequent saving in cost of hydraulic and electrical equipment and structures.[3]

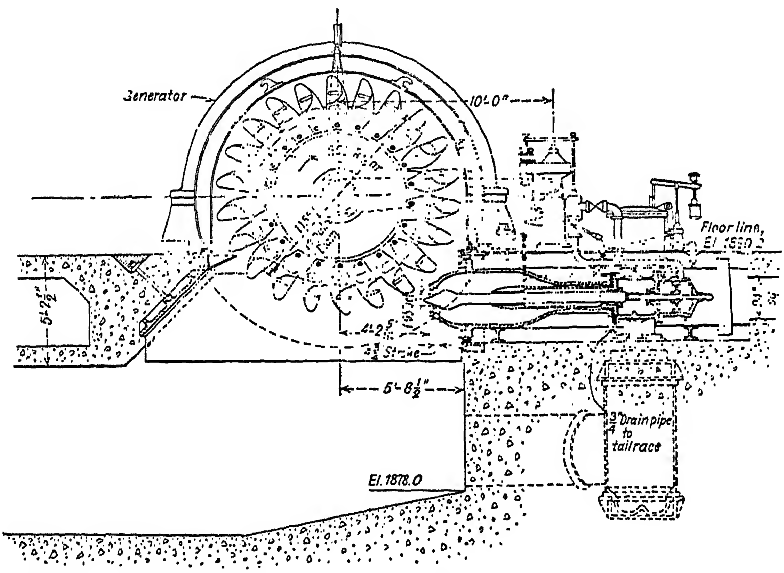


FIG. 26. Typical impulse or Pelton wheel installation. (From Hydro Electric Handbook, Creager & Justin, John Wiley & Sons, Inc., page 595.)

An important current development is the use of the propeller type of unit with movable blades, the angle of the blades being automatically adjusted by the governor so as to attain the greatest efficiency for any given loading of the unit. The propeller type of unit with fixed blades has a steep efficiency curve with a sharp peak, so that for all points, except that of maximum efficiency, the efficiency is relatively low. Making the blades of the propeller type unit automatically adjustable

[3] For further details on the various types of hydraulic turbines and their application, see "Hydro Electric Handbook," Creager and Justin, John Wiley & Sons, Inc., New York.

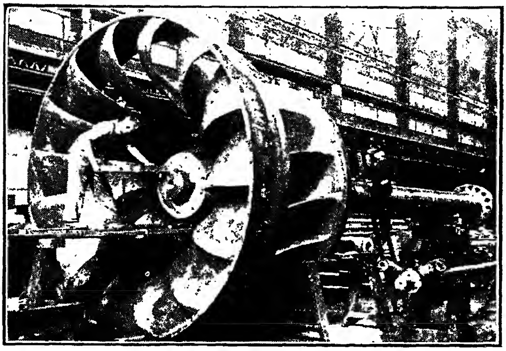


FIG. 27. Francis type runner (Allis-Chalmers), 24,000 hp at 70 foot head. (From Hydro Electric Handbook, Creager & Justin, John Wiley & Sons, Inc., page 615.)

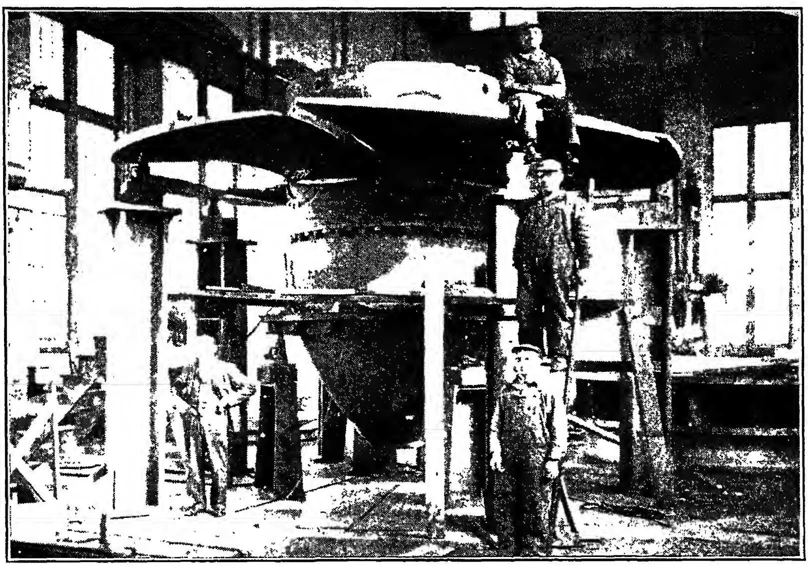


FIG. 28. Smith-Kaplan adjustable blade runner for Safe Harbor development, 42,500 hp at 55 foot head, 109.1 rpm. (Courtesy of S. Morgan Smith Co.)

by the governor has made this unit more efficient at part gate openings than the usual Francis runner.

For heads up to about 50 ft, and for units which must operate at varying load, this is a development of great importance and permits the attainment of a materially higher average overall efficiency. For units which can be operated always at point of maximum efficiency, or not at all, the use of the governor controlled, automatically adjustable, propeller type runner is an

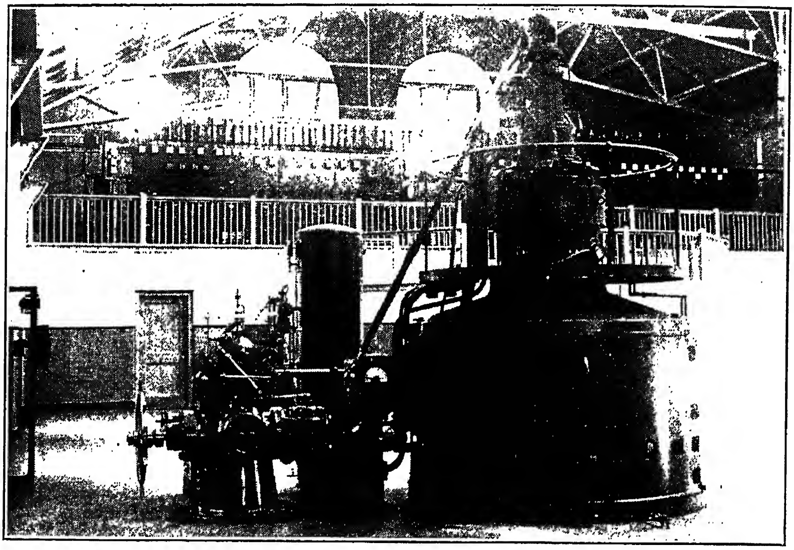


FIG. 29. Power house view of Kaplan type hydro electric propeller unit at Little Falls, N. J. Plant of Passaic Valley Water Commission. Head 32 feet, 900 bhp, 360 rpm. (Courtesy of W. M. White, Chief Engineer, Hydraulic Dept., Allis-Chalmers Manufacturing Co.)

unnecessary expense, and in such circumstances, it is usually economical to use either the Francis type unit or the fixed blade propeller unit. Figure 31 shows the comparative efficiencies of propeller unit with automatically adjustable blades, a high speed Francis unit and propeller unit with fixed blades for various percentages of full load.

The recent development of a hydro electric unit which will pump water or generate power at equal efficiency up to heads of 300 ft or more has greatly extended the economic application of pumped storage hydro electric plants. (See also Chapter XII, Section 169.)

114. Types of Hydro Plant Settings. — For very low heads from 15 ft to about 40 ft, and unit capacities up to about 2000 hp, open flume settings with vertical runner of the Francis or propeller type are applicable. Usually the propeller type runner

FIG. 30. Kaplan adjustable blade runner for Safe Harbor development on the Susquehanna River, 42,000 hp, 55 foot head, 109.1 rpm. (Courtesy of I. P. Morris & De La Vergne, Inc.)

will work out as the most economical in such cases because of higher speed and larger power in a given setting.

For unit capacities in excess of 2000 hp and for heads as great as about 50 ft, concrete spiral settings are usually more economical. Here also there is usually a definite advantage in utilizing

the vertical propeller type of unit. There is some overlapping, but it is believed that in general, for heads much in excess of 50 ft, it will be found more economical to utilize plate steel spiral settings. For heads much above 50 ft, the use of the propeller type unit becomes more questionable. For high heads, the Francis type of unit, sometimes horizontal and sometimes vertical, is used frequently with cast steel spiral setting. For the highest heads from 850 ft up, the impulse wheel is used.

115. Run of River Hydro Plants. — A run of river hydro electric plant is not provided with seasonal storage, either at

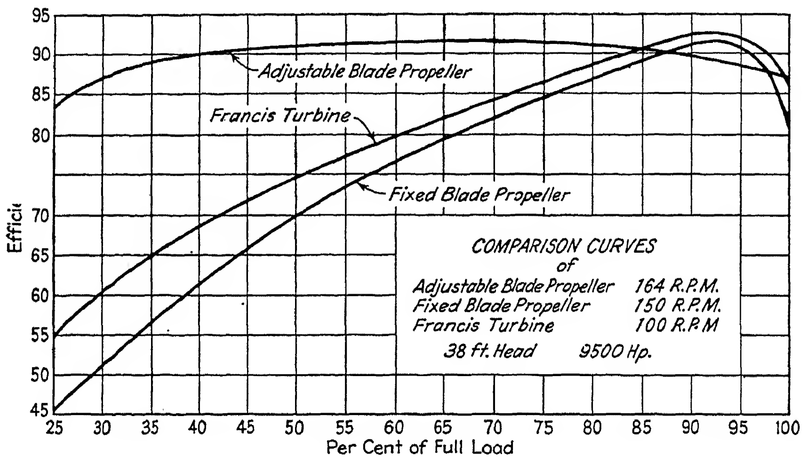


FIG. 31. Comparison curves of different types of hydraulic turbine runners for low heads. (Courtesy of S. Morgan Smith Co.)

the plant or at some other point higher up on the watershed. Such a plant must utilize the flow of the river as it comes, or let it pass by without utilization. A run of river plant may or may not be provided with pondage. By pondage is meant sufficient storage at the plant to take care of the day to day fluctuations in the use of the plant throughout the period of a week.

When it is stated that a plant has ample pondage, it is usually meant that the pondage is sufficient to permit the installation at the plant to deliver during low water conditions the output represented by one week's flow of water in any manner which may be required by the load curve. Run of river plants frequently prove economical as part of a system, including both steam and hydro plants, when ample pondage is available, but without such

pondage their construction is seldom attractive. At Conowingo, Muscle Shoals, Safe Harbor and Keokuk are examples of run of river plants with ample pondage.

116. Base Load Hydro Plants. — Base load hydro electric plants are plants which have such a steady stream flow available that they are able to operate day in and day out throughout the year at or near 100 per cent capacity factor. The Niagara Falls plants and the plants along the St. Lawrence, such as Cedar Rapids and Massena, are examples of base load hydro electric plants. Such plants are usually economically desirable only under conditions where it is practicable to utilize only a relatively small part of the total flow of a stream. A plant with storage may be a base load plant, but if storage is installed, it is usually economical to make the installation very much larger than would be necessary for a base load plant.

In reservoir plants where conduits are necessarily long and expensive, it is sometimes economical to make the installation on a high capacity factor basis, thus making the plant a base load plant. There are a number of plants of this general type on the Pacific Coast, the peak load service being performed in part by steam plants at or near the load center.

117. Peak Load Hydro Plants. — A peak load hydro electric plant is, as the name implies, one which carries peak loads. A run of river plant provided with ample pondage may act both as a base load and as a peak load plant. When the stream flow at such a plant is equal to or greater than plant capacity, the plant operates on the base of the load curve; and when stream flow is less than plant capacity, it is ponded up during the off peak hours and utilized to permit all or substantially all of the capacity to operate over the peak. Conowingo is a good example of a hydro electric plant which performs both base load and peak load service. When acting in the former capacity, steam plants operate to carry the peak loads; when performing the latter function, they operate on the base of the load.

A plant which has a large amount of available storage, sometimes referred to as a reservoir plant, makes an ideal peak load plant, and frequently such a plant may be economically capable of utilizing many times the average annual flow of the stream and the annual capacity factor may consequently be very low, but the plant is always available to go on the line at full capacity and carry the short time peaks of the system. In the Niagara

Hudson Power system, for instance, there are a number of plants of this character, as well as pure base load hydro plants and run of river plants which perform either function according to whether the stream flow is high or low.

Pumped storage hydro electric plants, or plants which pump a part or all of their water supply[4] to their reservoir, are commonly purely peak load plants, and generally are economical only in systems subject to unusually sharp peaks which would otherwise have to be carried by steam plants.

118. Factors Affecting Proper Size and Number of Units. — As a rule it is advisable to have all the units in any one plant of the same design and size. This simplifies the making of repairs and replacements, and decreases cost. A single spare runner may be carried in stock and a single set of spare parts.

If there is no other power plant in the system, the required capacity should be divided into a number of units. Unless such a procedure results in units of an impracticably large size, the maximum size of unit should be that required to carry the base load, that is, the load which is continuous throughout the whole 24 hours of each day. Assuming that ample water supply is always available, the installation should be sufficient to carry the maximum load of the system with at least one additional unit as a spare in case of a breakdown during peak load conditions. Thus, if the base load were 20 per cent of the maximum, which is quite a usual condition, there would be at least six units and perhaps more in the plant. At one time there were a number of plants of this kind in the United States, and there are still some in Canada.

Under present conditions in the United States, however, such plants are seldom economical as the total installation, excluding the spare unit, is limited to that capable of utilizing the minimum flow of the stream. During the off peak hours, a large amount of stream flow is wasted which might be turned into secondary power if there were a market for it. Most of the plants of this sort which were originally built to serve independently a particular load curve have since been interconnected, becoming a part of a large power system, thus changing their status to that of a base load plant operating practically at full capacity all the time. Ordinarily it is not economically advisable to plan on installing only up to the capacity which will utilize the minimum flow of the stream.

[4] See Chapter XII, Section 169.

Even before the existence of the large interconnected systems, it had become usual practice to install capacities greatly in excess of minimum stream flow. If the plant was a run of river plant without pondage, the maximum size of unit practicable was that size which could just utilize the minimum flow of the stream. If pondage was available, the maximum size of unit might be several times that required to handle the minimum flow. Additional units were then added sometimes up to a point where all of them could operate at full capacity for perhaps only 30 per cent of the time during an average water year. Several of these plants were interconnected to serve the load curve of the territory entirely from hydro power, and the secondary power, or a part of it, which was available a large part of the time either was sold at a low rate to some industry such as the paper mill industry, which could use intermittent power, or else was exported to a neighboring utility which utilized steam power and sold at or below the marginal cost of steam generated energy.

For a modern hydro electric plant forming part of a large system containing both steam and hydro, it is still necessary to limit maximum size of units to that capable of utilizing the minimum flow of the stream if the plant is a run of river plant without pondage. However, if ample pondage is available, this limitation does not apply and the maximum size of unit may be anything up to the practicable physical limit of size aside from any limitation which the characteristics of the load curve may place on the unit. Thus we would not want a unit so large that its capacity was equal to 50 per cent of the peak load and could operate at times of minimum flow for only four hours a day at full capacity. If such a unit were chosen, it would probably have to operate at very inefficient gate openings for a large part of the time during periods of relatively low stream flow in order to fit itself to the upper portion of the load curve. Considering the usual shape and form of daily load curves, it is good practice to limit the maximum capacity of a single unit to one-fifth of the peak load.

In a modern power system containing both steam and hydro plants, it is seldom necessary for hydro plants to have more than two or three units unless units are so large as to equal the maximum practicable size. Single unit plants are in fact frequently advisable. The cost per unit of capacity goes down quite rapidly with increasing size. With hydro electric generating units having

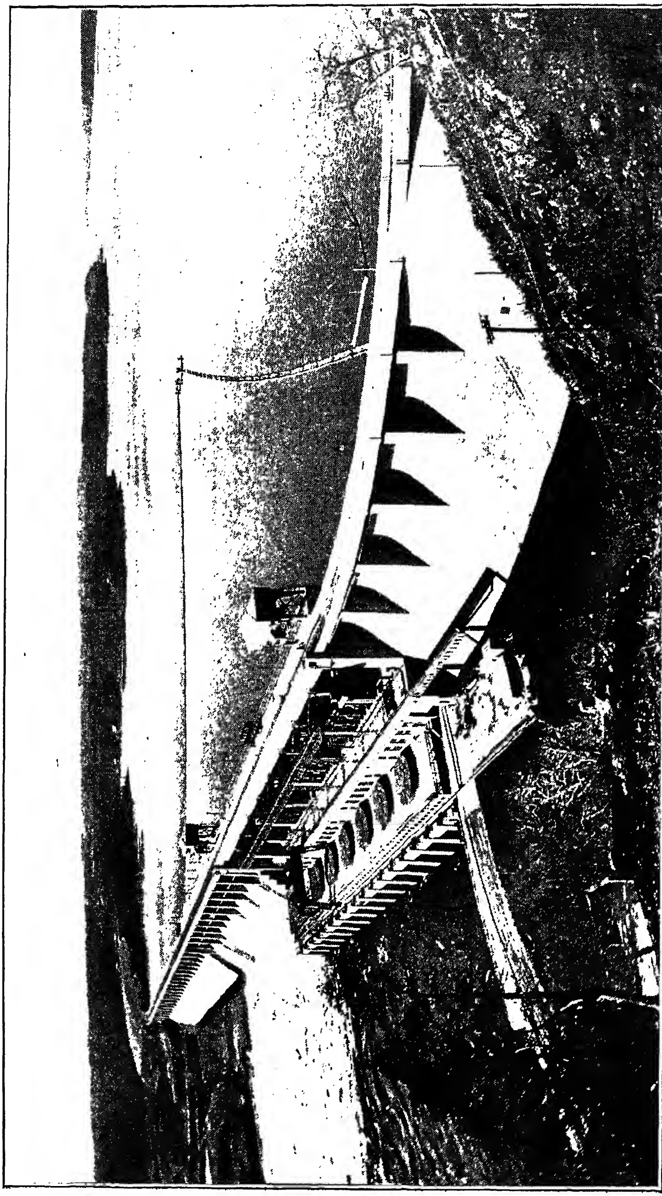


FIG. 32. Bagnell Development, 129,000 kw at 90 foot head. Note omission of power house superstructure. (Courtesy of Union Electric Light and Power Co., St. Louis, Mo.)

a service demand availability factor of 99.55 per cent, there is no logical argument which can be advanced against the single unit plant.

119. Savings in Space in Power Houses and Open Air Type of Power Houses. — The hydro electric plant is inherently simple in design as compared to other power plants. Much progress has been made in recent years in the design of equipment and structures to produce more power in less space at lower cost, and there is still room for improvement. For a given amount of power at given head, power houses are very much smaller and less costly than they were only a few years ago. Designers are striving to eliminate all unnecessary structure from the power house. The Bagnell development in the Ozarks, Mo. (Fig. 32), and the Norwood development in North Carolina, are examples of achieving a considerable saving by eliminating the superstructure of the power house — the so called open air power house.

120. Propeller Type Runner Opens Promising Field for Economies. — For relatively low head plants, the propeller type of runner[5] with its ability to pass larger quantities of water through the same sized opening, and thus obtain more power in the same space, has opened up a wide field of economic application. By increased speed it has also decreased the cost of the electrical generators per kilowatt of capacity.

Many low head hydro electric plants, built before the development of the propeller type of runner, might advantageously be revamped by substituting for the old style low head Francis runner a high speed propeller type runner, together with the necessary changes to draft tubes and electrical equipment. In many plants, leaving the old speed ring and wicket gates in place, a propeller type unit might be substituted for the existing Francis runner, and, as a result, the average annual output of the unit would be increased from 25 to 50 per cent. Usually a lengthening of the draft tube will be required, a higher speed generator of increased capacity may have to be substituted and other electrical changes made. However, the return on the investment of new capital required to make these changes is frequently very high indeed.

121. Omission of Governors on Some Units Feasible. — In a system which includes a number of units, both steam and hydro, located in various plants, most of the hydro units should either be

[5] See Section 113.

operating at point of maximum efficiency or not at all, and the variation in load should be taken at a relatively few units of plants particularly suited for the purpose. It is at these latter units that all the governing should be done, in an ideally operated system. In the operation of such large systems, even though all the units may have governors, many of the units are blocked or operate on the load limiting devices so that the governors do not operate unless there is a large change in load. This being the case, it is unnecessary to provide governors for most of the units.

Particularly for the smaller units, the governor and attendant tanks, piping, compressor and pumps account for a large percentage of the total cost of the unit. So why not omit them in many cases? The authors believe that in this matter, as in many others, tradition and human inertia are responsible for much capital expenditure which might better be avoided. Recently a number of plants have been constructed without governors, and the gate mechanism is motor operated with overspeed fly ball control switch which automatically starts the motor closing the gates when the speed rise reaches about 10 per cent. The closing time provided for is usually about one minute. When units are intended to operate without governors, they should be capable of operating at runaway speed for a material length of time without injury.

122. Advantages of Cylinder Gates for Decreasing Cost and Minimizing Leakage. — It is usually a difficult problem to keep wicket gates tight, and in many plants a considerable percentage of the energy which might otherwise be turned out is wasted by leakage through wicket gates when the unit is shut down. In many plants it is not the practice to lower the head gates unless the unit is to be out of service for a long time, and anyway many head gates are far from tight. Many years ago the cylinder gate was discarded by turbine manufacturers because at part gate opening it caused the unit to be very inefficient. The cylinder gate, however, has these advantages over wicket gates: It is much cheaper, and it is practicable to make it almost drop tight when in a closed position. In a modern power system where most of the units can operate at point of maximum efficiency, it should be practicable to omit the guide vanes and merely have the stationary vanes of the speed ring with a simple cylinder gate which would either be closed tight or be wide open. In the last few years several new units have been equipped with cylinder gates.

123. Possible Savings in Head Gates for Low Heads. — If a plant containing several units were equipped with cylinder gates as suggested above, it would also be practicable to make a considerable saving in the cost of head gates. A single set of weighted head gates, usually enough for only one unit, might be provided which could be so arranged that it could be operated by the power house crane.

124. Possible Savings at Intake Structures and Racks. — There is also opportunity for simplifying, and thus making savings, in many intake structures. The usual rack structure and the racks themselves are sometimes quite expensive and are designed for a considerable head differential. The spacing used in rack bars is to some extent traditional. Spacing of rack bars for the old style small size Francis units, with their relatively small water passages, is unnecessarily close for modern large units with their large water passages. With large propeller type units, the spacing may successfully be as much as 6 in., and many such units have been operated continuously for months without any rack bars at all. Such units pass any ordinary trash without the slightest difficulty, but it is necessary to keep large timbers and people from getting into the units while in operation. A coarse network made of wire rope with a 6 or 8 in. mesh would accomplish this purpose just as well and at much less expense than the usual racks and rack structure. Particularly in low head plants, there is opportunity for making material savings in the layout and arrangement of head gates as already indicated.

125. Economies Possible in Electrical Layout. — When there are a number of hydro electric plants in a system, there is not the same need for flexibility that exists in a plant which is the only hydro electric plant in the system. Consequently, many of the recent plants omit the low tension station bus and connect the generators right through to the bank of step-up transformers which put the electric current on the transmission line.

126. Automatic Operation and Remote Control. — Automatic operation or remote control offers an opportunity in the smaller hydro plants for making a material saving. Probably one or the other of these features could economically be utilized in 80 per cent of the hydro electric plants of less than 5000 kw capacity with appreciable economic advantage. In small hydro plants, the cost of attendance becomes a material percentage of the total annual cost, and there are a good many prospective hydro

electric projects of small capacity that would prove economically desirable provided that automatic control was introduced. Many small plants so equipped require only a daily visit from a patrolman. There should be a great many more plants so equipped.

127. Possible Savings in Dams, etc. — The greater portion of the investment in a hydro electric project is usually in the dams, spillways, reservoirs, lands and riparian rights. Of the total investment in hydro projects, from 20 to 35 per cent is usually represented by the investment in power house, equipment, penstocks, pipe lines and intake, and the remaining 65 to 80 per cent is investment in dams, reservoirs, lands and riparian rights. Consequently, it is desirable to investigate very carefully the possibilities of savings in these latter items. The general design of the project has a great influence on these costs, as does also its location in reference to topographical and geological features. The general design of any proposed hydro electric project should be thoroughly investigated and studied under the guidance of hydro electric engineers of wide experience.

For any particular case, it is possible to utilize a type of dam which is particularly suitable and economical for the given conditions. Thus, in some cases, a material saving may be effected if, instead of having a long spillway section of dam, provision is made for passing the flood water through a section of gates which have a high capacity per foot length of crest, and then the rest of the dam is made a non-overflow masonry section, or even an earth or rock fill dam.

Multiple arch, arch and flat slab reinforced concrete dams also sometimes work out more economically under certain conditions than other types. Alternative plans for various types of dams and spillways should be analyzed to determine which type will give the lowest total cost for the given conditions.

A new possibility for saving in the cost of some dams has been created by the development of stainless steel. Some of the early attempts to use steel for the construction of dams met with failure. The condensation of moisture, and the presence of air in the interior of such steel dams, created a condition which was highly favorable to rapid corrosion.

If we should design the deck of such a dam of stainless steel plates electrically welded in place and, for structural members, use heavy lead dipped or galvanized sections, the structure could

be made permanent and tight, and it is probable that in many cases it would be considerably the cheapest sort of dam which could be built. So why not give the steel dam another chance?

128. Minimum Cost of Power and Not Monumental Structures Is the Goal. — The above discussion does not pretend to summarize all the various ways in which savings may be made in the design of a hydro electric project. However, it is intended to indicate that economies may be obtained if all the conditions in any given case are studied and analyzed from an economic standpoint, and if the men responsible for design and construction will always keep in mind that it is their particular function to secure for the company the required quantity of power at the lowest possible total annual cost and that they do not hold any commission to build any elaborate monuments to themselves or anybody else.

CHAPTER IX

ECONOMIC FUNCTIONS OF HYDRO ELECTRIC PLANTS

129. Agitation for Development of Water Power. — Publicists and politicians wax eloquent over the wasted power of falling water, and a continual agitation is conducted in favor of the so-called conservation of the water power resources of the nation and their development for the benefit of the people, by which is usually meant their development by government. The impression created in the mind of the casual observer is that water power is a God given source of cheap energy obtainable at a cost far below that of steam power.

This agitation has created a public opinion which has been sufficient to force the development of some water power projects at government expense, as at Muscle Shoals and the Hoover Dam. Indirectly the pressure of this agitation has also led, in some instances, to the construction of hydro electric projects by public utility companies, which were not economically justifiable at the time. The present work is not concerned with the pros and cons of public ownership, but it should be noted in passing that thorough economic studies have little influence on decisions arrived at in an atmosphere of popular clamor. In every proposed development, the sole question on which a decision as to whether or not construction should be undertaken should be: " Will the proposed development reduce the total cost of power?" If it will not, most emphatically it should not be undertaken. A true answer to this question in any specific case cannot be found in the speeches or writings of publicists or in the calculations of copybook engineers, but can be obtained only as the result of thorough economic studies and investigations on the part of competent authorities.

However, the mere fact of this public agitation in favor of water power should make public utilities anxious to investigate the economic feasibility of any water power resources in their territory.

130. Water Power Not Necessarily Cheaper than Steam. — As the capital cost of hydro electric projects is usually very much

higher than the capital cost of steam plants, it follows that, when we substitute a hydro electric plant for a steam plant, we are exchanging the low fixed charges and high operating costs of steam for the high fixed charges and low operating costs of hydro. In order for us to come out whole on the proposition, it is necessary for the sum of fixed charges and operating costs on the hydro plant to be equal to or less than the sum of the fixed charges and operating costs on the steam plant. It sounds like a simple problem, and it is just as simple as all problems are when they are boiled down and all the modifying "ifs" and "ands" removed.

Water power is not necessarily cheaper than steam power, and in many cases, even where suitable water power sites are available, the requirements of the territory for additional power can be more economically met by the construction of steam plants. As shown in Chapter IV, there has been a great advance during the past ten years in the art of generating electric power in steam plants. This advance has led to a profound change in the economic relationship of steam and hydro, and has necessitated the making of a very careful economic analysis each time that it becomes necessary to increase the capacity of a power system in cases where the required increment of capacity may be furnished by either steam or hydro.

131. Steam the Yardstick for Measuring Hydro. — Steam plants and hydro plants are the two main sources of power supply. As a rule, no extensive economic investigation is required to show that a steam plant will satisfactorily supply the increasing demands. Accordingly, in most sections of the United States, when a power company is faced with increasing requirements for power and energy, the first thing that the utility executives think of is an additional steam plant or an extension to an old steam plant. Consequently, steam has become the yardstick by which hydro must be measured.

132. Hydro and Steam Complementary Sources of Power Supply. — In many modern power systems containing both steam and hydro capacity, the two sources of power supply are no longer competitive, but are truly complementary sources of power supply, and it has frequently been found that a system which includes both hydro and steam capacity in proper economic balance has a lower total cost of power than it would have if its entire power supply were obtained from one or the other source.

133. Future Field for Hydro. — In a few specially favored sections where topographical and stream conditions are unusually favorable and where coal is expensive, the bulk of the power required will be produced in hydro electric plants, but throughout the greater portion of the country, the requirements for power will be met from thoroughly interconnected power plants, both steam and hydro.

Usually the major portion of the power will be furnished by steam plants, and hydro plants will be designed and built in most cases as complementary sources of power to serve a given load curve in conjunction with steam plants, instead of being built as a major source of power supply. Undoubtedly hydro installations will be on a higher basis in relation to available stream flow than at present. Utilization factors will be higher and annual capacity factors lower. Probably very few plants will be built without adequate pondage, and peak load hydro plants will be much more common than at present.

134. Economic Evolutions in Functions of Hydro Electric Plants. — Since the introduction of hydro electric plants on a large scale about 1890, a gradual evolution has taken place in the economic functions performed by them. At first, a hydro electric plant was usually the sole source of power of a community or section. Accordingly, installation was necessarily based on minimum flow. Next storage was added, thus increasing the minimum flow and permitting the installation of additional capacity. Then just a little more capacity was put in, principally because the incremental cost was low, even though only enough water was available to operate the additional units for, say, seven months of the year. A standby steam plant often in the same building was added to supplement the extra hydro units at times when there was not enough water to operate them. Finally the hydro plant became a part of a great interconnected system embracing both steam and hydro power. These phases in the evolution of hydro power are briefly discussed in the three sections which follow.

135. Hydro Plants as an Exclusive Source of Power. — Some years ago, many power systems in America were served exclusively by hydro electric plants, but now there are only a few. To serve successfully a given load exclusively by hydro electric plants, it is essential that the minimum flow of the stream at time of maximum load be sufficient to furnish all the power required to meet that load.

Unless adequate storage was provided, there was, accordingly, a great waste of water over the dams for the greater portion of the year. Thus minimum flow at time of peak load was the criterion for determining the permissible installation. The investment in dams, lands and riparian rights was necessarily high relative to the investment in power house equipment, conduit and intake. As a result, the total cost of the development was high per unit of installed capacity.

For instance, a certain hydro electric plant having an actual present capacity of 250,000 kw has a capital cost of $200 per kw. If it had been necessary to have this plant as a sole source of power, the installation would have had to be limited to the power which could be turned out with the minimum stream flow available at time of peak load, in this case 50,000 kw,[1] and the capital cost would have been nearly $1000 per kw.

Many of the companies which served their load curves from hydro plants exclusively, adopted the practice of basing their installations on flows considerably greater than the minimum. This was because the incremental cost of the additional installation was very low. Thus, during a large part of the year, these companies had available surplus hydro electric energy which was not salable on any normal utility load curve. A part of this secondary energy was sold on a "when, as and if available" basis to industries which could afford to shut down a part or all of their operations during periods of low water as, for instance, the paper mill industry, but a very large percentage of all the energy available in the river was wasted.

136. Development of Storage for Hydro Electric Power. — With the development of the steam plant to higher and higher efficiencies, it soon became uneconomical in most cases to install hydro electric plants on the basis of minimum flow. Accordingly, storage was added, thus permitting an increase in installation to such an extent that hydro electric power could again compete with steam power. In many sections where natural conditions were favorable and particularly where topographical conditions permitted storage at reasonable cost, there developed many successful power companies which obtained all or very nearly all of their power requirements from hydro electric plants.

[1] This installation is based on minimum December stream flow and a 50 per cent daily load factor, as the plant has ample pondage.

Among the sections where this development was particularly marked may be mentioned New England, the Pacific Coast, northern New York, the Piedmont section of the southeastern states and Michigan. This era coincided with the development of long distance high tension transmission, and to a very large extent the development of long distance transmission lines was due to the necessity for transporting the hydro electric power long distances to market. In California, where, before the development of oil and gas wells, fuel was expensive, hydro plants with storage were developed in the mountains and the power shipped to the cities over high tension lines.

In most cases it was found, however, that it did not pay the hydro companies fully to regulate a stream by means of storage. It was found practicable to supply the load requirements entirely from hydro, but utilization factors were low. By utilization factor is meant the ratio of the actual energy which a hydro plant is able to generate on the load curve to which it is connected during the year, to the energy which it is capable of generating with the existing installations and prevailing stream flow during the same year. In many cases, utilization factors for purely hydro companies were as low as 40 per cent, and they seldom exceeded 70 per cent.

Accordingly, as the load increased, some of these companies built steam plants to act as standby plants when ample stream flow was available, and to operate on the load curve during the months of the year when stream flow was deficient. After adopting this procedure, they found that utilization factors were greatly increased and that the total cost of power was much less than it would have been if the growth in the power requirements of the load curve had been supplied by constructing a new hydro electric plant. Other hydro companies sought and obtained alliances and interconnections with companies having a preponderance of steam capacity in their system, and thus ushered in the era of interconnection.

137. The Era of Interconnection. — The present period in the development of power may be designated the era of interconnection. Although we are still in the early stages of this era, it has radically affected the economic relationship of many factors in the public utility industry, including the economic relationship of steam and hydro power.

It was found that interconnection between companies pro-

duced large savings through diversity in load, reduction in necessary reserve capacity, diversity in construction programs, higher utilization factors on hydro plants and high capacity factors on the more efficient steam plants. Also, because of the resulting larger connected load, new capacity could be installed in larger and more efficient units and could be quickly loaded up. (See also Chapter XIII.)

We are now approaching a condition where, instead of a large number of power companies serving individual communities or districts, we will have extensive regions served by a single interconnected power system. Already there are several well integrated interconnected systems having a load approaching or exceeding a million kilowatts. The era has been marked by a material decrease in the cost of electric power from the larger new steam plants. Manifestly all these new conditions have materially altered the economic relationship of steam and hydro.

138. Firm Capacity of Hydro Electric Plants. — It is practically always possible to take care of the growth in the load of a power system by installing an additional steam plant. In most modern interconnected power systems, the load is supplied by a combination of both steam and hydro plants, or else by steam plants alone. Accordingly, when a hydro plant is proposed as an alternative to installing additional steam capacity, the first question which arises is: "Can the proposed hydro installation do the same work which an alternative steam plant might perform on the load curve?" If the answer is "Yes," then the hydro capacity is said to be firm capacity.

The firm capacity of a hydro electric plant may be defined as that portion of its total installed capacity which can perform the same function on that portion of the load curve assigned to it as alternative steam capacity could perform.

Firm capacity is dependent on the minimum stream flow available at time of peak load, on the pondage available, on the shape and size of the connected load curve and on the interrelation of existing plants. Occasionally engineers speak of the minimum 24 hour power available at a hydro plant as the firm power capacity of that plant. The two can be the same only in the case where no pondage at all is available at the plant. With large pondage and favorable load conditions, firm capacity may be many times the minimum 24 hour power available at the site.

The importance of firm capacity in affecting the earning power

of hydro plants is indicated in run of river plants without pondage. If such a plant, in addition to the liability of having no pondage, is also subject to the liability of being drowned out and thus becoming inoperative at the time of the system peak load, it then has no firm capacity and the only earnings creditable to it would be those from the energy which it generated at the marginal value of steam produced energy, or perhaps 2 to 3 mills per kwhr.

The firm capacity of a hydro plant may vary at different seasons of the year, but usually it is firm capacity at time of system peak which is of significance, and, unless otherwise specified, it is to be understood that the term " firm capacity " means the firm capacity of the hydro plant at time of system peak load.

The significance of firm capacity will be fully understood through a study of Fig. 33, which is the load curve plotted hour by hour for the week of greatest demand in the year for a regional power company whose territory includes a high percentage of urban population and industrial communities. In this system, the maximum demand week always occurs in December, and there is already constructed in the system one hydro electric plant having a capacity of 38,500 kw. The pond at this hydro plant is of ample capacity for providing weekly regulation with an insignificant drawdown. The minimum river flow in December is sufficient to provide 440,000 kwhr at this plant during the week. Measuring down from the peak load ordinate of 175,000 kw, a distance corresponding to 38,500 kw, a horizontal line is drawn across the diagram. In the area thus cut off at the top of the load curve, it is found that there are 438,000 kwhr. As this is slightly less than the energy available at the plant during a minimum flow December week, it is evident that the entire installed hydro capacity would be firm on the load curve, for it would be able to perform the same function as alternative steam capacity could perform operating on the same portion of the load curve.

If the characteristics of the annual load curve were not already well known, it would be necessary to go further and examine the load curves for other weeks in other seasons of the year, each time measuring down 38,500 kw from the annual peak and making sure that the energy thus cut off was not more than that which could be relied on as available at the plant during that particular week.

Now in this same system the addition of another hydro plant is being considered, the proposed installation for which is 15,000 kw. The proposed plant would have ample pondage for weekly regulation, and during a week of minimum December flow could produce 608,000 kwhr. Manifestly, in position on the load curve, the old plant would take precedence over the new. That is, the peak loads are already taken care of by the old hydro plant

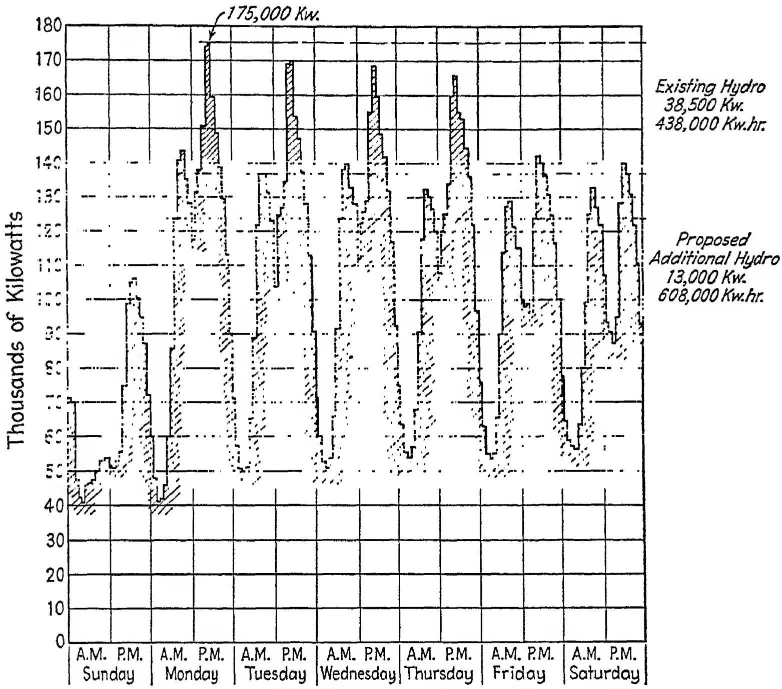


FIG. 33. Load curve, week of maximum demand in December, 1937, Regional Power Company. Peak 175,000 kw. Energy for week 17,000,000 kwhr. Load factor for week 57.8 per cent.

and consequently the new plant, during a week of minimum December flow and maximum demand, will have to take care of a lower portion of the load curve having a higher load factor. By trial and error, it is established that in a band across the load curve (immediately below that taken care of by the old hydro plant) containing the 608,000 kwhr available, there would be required 13,000 kw of capacity. Thus, of the 15,000 kw of installed capacity, 13,000 kw would be firm capacity in the given

year (1937). By analyzing load curves of the system for future years, it is found that in 1939 the entire proposed installation for the new hydro plant will be firm.

Before leaving the discussion of Fig. 33, it should be noted that, as more years pass, the old hydro plant (capacity 38,500 kw) will move down somewhat on the load curve. In other words, the band across the load curve containing the amount of energy available at the plant during a week of minimum December flow and maximum demand will not include the top of the maximum peak load but will leave some of the peaks projecting above it. When this time occurs, it may provide an opportunity for the installation of an additional hydro plant perhaps of the purely peak load type.

Actually the labor involved in determining when proposed hydro capacities will become firm is not excessive, as it is not necessary to use the trial and error method referred to above and computations may be abbreviated by means of curves, as discussed in the following section.

139. Load Duration and Peak Percentage Curves. — To prepare a mathematical curve for the above use, the first step is to obtain a load duration curve for the period under consideration, such as that described in Chapter IV, Section 54. Figure 34 shows such a duration load curve for the peak load week of December. This is not for the same load as Fig. 33, but for another load curve of somewhat different characteristics. As presented, ordinates are given as percentages of total load and abscissae are hours' duration. Areas underneath the curve represent energy. Taking the load duration curve and beginning at the top, cumulative areas are determined by increments by planimetering or otherwise. From the data thus obtained, the peak percentage curve shown in Fig. 35 is plotted. Figure 35 is for the same load as Fig. 34. Figure 35 is plotted on a percentage basis and therefore may be applied to any year so long as the load factor and load characteristics do not change. It shows the percentage of the total energy for the week which there will be in any given percentage of total load measuring down from the top. Thus, 20 per cent of the load will contain only about 2 per cent of the energy. Peak percentage curves like Fig. 35 are very useful in all economic studies in which the firm capacity of hydro plants is involved. For precise studies such curves are prepared not only for the peak load week but also for a typical week in each month.

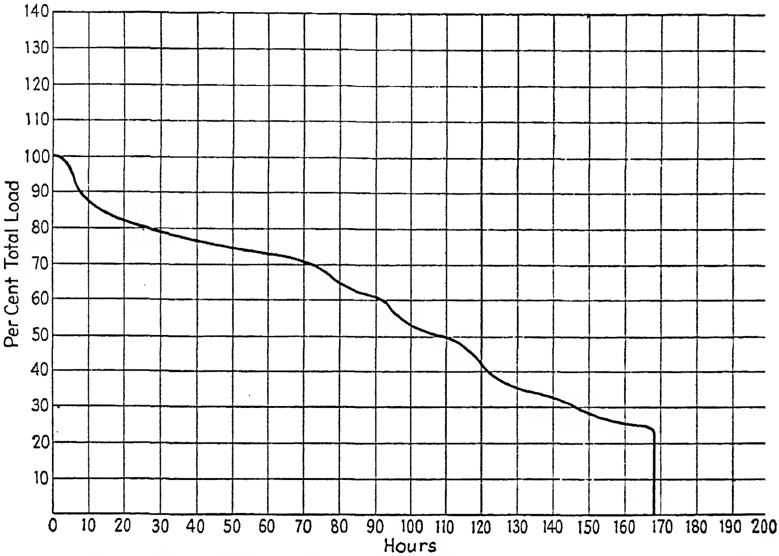


FIG. 34. Load duration curve. For peak load week in December of large power company. Load factor for the week 59.1 per cent. 1930 peak 492,000 kw. 1930 energy for week 48,850,000 kwhr.

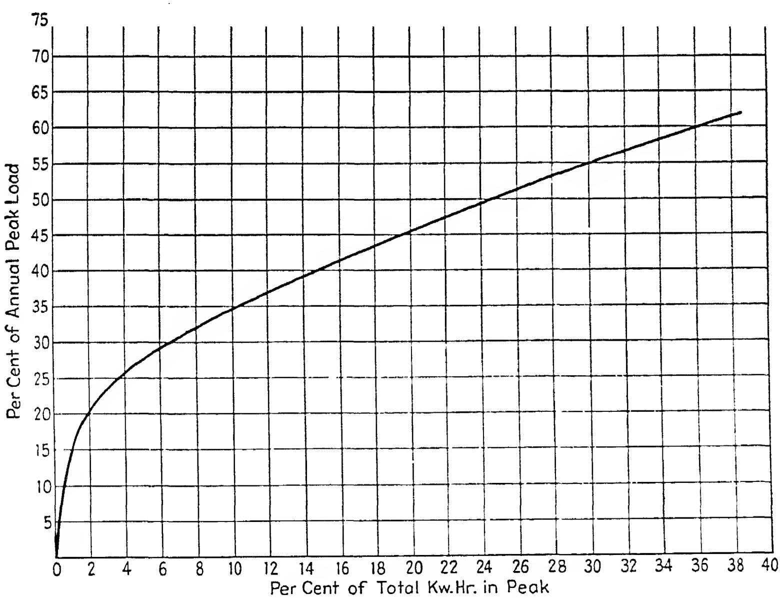


FIG. 35. Peak percentage curve for peak load week in December of large power company. Load factor for week 59.1 per cent. 1930 peak 492,000 kw. 1930 energy for week 48,850,000 kwhr.

To illustrate further the use of such curves in connection with hydro studies, a sample illustration will be given.

Assumption. — The power system represented by Figs. 34 and 35 has at present its entire generating capacity in steam. Existing steam plants will soon be loaded up and additional capacity must be provided. The advisability of adding hydro capacity to the system instead of steam is being considered and an option has been secured on a site for a hydro plant. At the site it is feasible to develop 100 ft of head by means of a dam which will provide ample weekly pondage with slight drawdown. The river is a large one, but the minimum flow in December is so low that during such a period only 3,000,000 kwhr per week will be available, although during a large part of the year there is a high flow in the river.

Question. — What is the maximum size of installation which can be installed and have it all firm capacity in the year 1935, assuming a peak load of 700,000 kw for that year and energy output of 69,000,000 kwhr during the week of maximum December peak?

Solution. — The hydro plant can be relied on to produce only 3,000,000 kwhr during this critical period, which is (3,000,000 $\div$ 69,000,000) = 4.35 per cent of the total energy in the load curve for the week. Referring now to Fig. 35, it is found that 4.35 per cent of the energy (abscissa) is contained in the upper 26 per cent of the load (ordinate). As the peak load is 700,000 kw, the greatest hydro capacity which could be installed and have it all firm capacity in 1935 is (0.26 $\times$ 700,000) = 182,000 kw.

From Fig. 34 and also from the annual load duration curve (not here reproduced), it is found that this is just about equal to the base load of the system. Consequently, at times of high water practically all the hydro energy which this hydro plant could generate could be absorbed in the system. In other words, the proposed hydro plant would have a high utilization factor.

If the system considered had already had in existence a number of hydro plants, the principle would be the same but more computation would be required.

140. Effect of Change in Load Factor. — So far, in the discussions of methods of determining firm capacity, it has been

assumed that the load factor remains the same. Although a gradual improvement in load factor is taking place and should be considered in precise determinations, the change is not rapid for any given territory and no serious error will usually be involved unless the attempt is made to predict a very long way in the future. When companies combine or interconnect, quite a radical change in shape of load curve and in load factor often takes place. In such cases it is necessary to make up new combined load curves and base peak percentage curves on them before proceeding with an analysis to determine firm capacity of hydro plants.

The question of a changing load factor is often brought up in connection with purely peak load hydro plants, such as Rocky River in Connecticut, which rely for their economic justification on the continuance of peak loads. Load factors will doubtless improve and the valleys in load curves will probably be filled in to some extent. Thus, a certain large power system already has an annual load factor of over 70 per cent. It has, however, peak loads of about the same nature as other companies, the difference being that the peaks bear a smaller relation to the total load.

Hence, as far as can be predicted at the present time, it appears that in the future we will have peak loads larger than the present (owing to growth in total load) but that such peaks will be a smaller percentage of total load than at present. All that this means is that using present load curves as a basis if we predict firm capacity for a hydro plant many years in the future it may turn out that instead of being firm in the year predicted it will not be firm until several years later.

141. Functions of Storage. — In a power system served by both steam and hydro, the true economic function of storage is to permit an increase in the amount which may be installed as firm capacity on the connected load curve at existing and future hydro developments on a given river system. Thus in Fig. 33, it is evident that if with minimum flow conditions only 200,000 kwhr of energy were available during the maximum demand week for the hydro plant at the top of the diagram, only a part of the 38,500 kw of installed capacity would be firm. If, however, sufficient storage were added to bring the energy up to 438,000 kwhr, then the entire installation of 38,500 kw would be firm capacity.

Such storage could confer a similar benefit on other developments on the same river. The storage would of course not be developed unless the increased revenue from the additional firm capacity at the various plants and projects thus permitted would carry the annual charges on the additional installation and on the investment in storage.

It is sometimes assumed that storage is merely of temporary advantage and that the same advantage could be gained by waiting a few years and letting the load curve grow until the proposed installation would be firm capacity. This is incorrect, however, as the addition of storage for any practical condition of present or future load curve will always permit the installation of additional firm capacity either in the same plant, in another plant or project on the same river or perhaps on an entirely different stream.

142. Economic Hydro Ratio of a Power System. — In any given power system served by both steam and hydro, there is an approximate economic balance between the proper amounts of steam and hydro installation. The " hydro ratio " is sometimes used to express the existing relationship. The hydro ratio is the ratio of the total hydro installation in the system to annual peak load.

If the existing hydro ratio is in exact economic balance, then the total cost of power supply is at a minimum for the existing conditions; and if the hydro installation were either more or less than this, the total cost of power supply would be greater. This is rather theoretical and not susceptible of exact determination, but nevertheless, the hydro ratio is sometimes quite useful as a rough guide in situations where conditions are thoroughly understood.

The proper economic balance at any given time between hydro and steam is largely dependent on the following factors: shape and magnitude of load curve, availability and suitability of economical hydro sites, length of transmission required for hydro projects compared to steam (" transmission liability "), run-off and its seasonal distribution for the streams available, availability and cost of storage, cost of fuel and availability of condensing water. Evidently, the economical hydro ratio may vary from zero where no favorable hydro sites are available, to 100 per cent in territories where there are hydro sites but where the cost of fuel is prohibitive.

In some sections where fuel is cheap but where suitable hydro sites are available without high "transmission liability" the economical hydro ratio appears to be from 25 to 40 per cent. In some other sections where fuel is somewhat more costly and hydro sites are particularly favorable the economical hydro ratio is from 60 to 70 per cent. In sections on the Pacific Coast, a marked change in the economical hydro ratio is apparently taking place from a very high ratio to a much lower one, largely owing to the advent of cheap fuel in the form of oil and gas in these sections.

Further increases in steam plant efficiencies and resulting decreases in the cost of steam generated electric power will tend to decrease the economical hydro ratio in some territories. On the other hand, further simplifications in the design of hydro plants and/or a decrease in construction costs, or a lowering of interest rates, will tend to increase the economical hydro ratio. In this connection, it should be remembered that a general decrease in construction costs or a general lowering of interest rates is relatively much more favorable to the construction of hydro plants than of steam plants, for the simple reason that the capital cost is usually much higher for hydro plants than for steam plants. Contra, a general increase in construction cost or interest rates is a factor favorable to the construction of steam plants instead of hydro plants. On the whole, it is believed that the increasing efficiency of the steam plant is leading to a change in the function and type of additional hydro electric plants tending to require a higher ratio of installation to available water supply and thus decrease the unit cost of the installation.

CHAPTER X

COST OF HYDRO ELECTRIC POWER

143. Capital Cost of Hydro Plants. — The capital cost of existing typical modern steam plants has varied by as much as 100 per cent.[1] Nevertheless, the general statement can be made that in many sections of the country it is feasible to build efficient modern steam plants of large size at a capital cost in the neighborhood of $100 per kw. The total cost of hydro electric plants has varied all the way from $125 to $350 per kw of installed capacity. One reason for this wider variation in cost is that the proportion of the total cost which represents field construction is much greater with hydro than with steam where a larger percentage of total cost is in equipment. Also, with hydro plants, a great variation in design is required to meet great differences in topographical and geological conditions. Such items of the cost of hydro plants as dams, lands, riparian rights, highway and railroad changes may be almost anything and bear no necessary relationship to the amount of installation.

This condition requires that first the amount of hydro capacity[2] which it is advisable to add to the system be determined and that then a very careful investigation be made to determine what water power site may be developed and what design adopted to secure a total cost of the power development which is the minimum feasible. For any given situation, there is a definite maximum limit to the permissible total cost of a proposed hydro electric development, and if the project cannot be built within this maximum limit of cost it is not economically feasible and should not be undertaken. To determine this maximum allowable cost, the annual value of the firm capacity and of the output of energy is determined by the methods outlined in Chapter XI and the two values added together.

This sum is treated as the annual revenue of the project, as in effect it is. From this is deducted the estimated annual operating and maintenance cost[3] for the project, and the remainder is the

[1] See Chapter VI, Sections 89 to 92 inclusive and Tables 9 and 10.

[2] See Chapter IX, Section 138.

[3] See Section 149.

maximum fixed charges which the project will stand. By dividing these total permissible fixed charges by the usual annual rate of fixed charges for a hydro project of this particular type, a capital sum is obtained which may be considered the maximum total cost which the project will stand. If the capital cost of the project exceeds this sum, then it would have been more economical to secure the additional requirements of power and energy from the alternative steam plant.

The following case serves to illustrate the above methods of determining in advance the approximate maximum limit for the cost of a proposed hydro electric project. A power company requires an additional capacity of 100,000 kw. If a steam plant is built, the annual capacity cost will be $15 per kw and the increment cost of energy will be 2 mills.[4]

A proposed 100,000 kw hydro plant would have all its capacity firm in the same year that the alternative 100,000 kw steam plant capacity would be required, and its average annual energy output would be 500,000,000 kwhr. As the base load of the power company exceeds 100,000 kw, all of this could be absorbed by the load curve. The maximum economic limit of capital expenditure is then determined thus:

100,000 kw firm capacity @ $15	$1,500,000
500,000,000 kwhr @ 2 mills	1,000,000
Total annual value of hydro project	2,500,000
Deduct operation and maintenance cost....	80,000[5]
Available for fixed charges on hydro project.	$2,420,000
Rate of fixed charges for project..........	0.09[6]
Maximum economic limit of cost for hydro electric project.........................	$26,900,000

If the estimate of cost for the project does not come comfortably within this figure, including any cost for transmission facilities required by the hydro plant and not by the steam plant, the project should not be undertaken.

Frequently the time element is of great importance in determining the economic feasibility of a hydro electric project. Thus, the above project at this time might cost more than the maximum economic limit, but if construction is delayed five years, the load curve will grow, and as a result, the firm capacity

[4] See Chapter VI. [5] See Section 149. [6] See Section 148.

which it will be feasible to install will increase. Perhaps at that time the firm capacity could be 150,000 kw and the project might then work out as economically advisable.

For this reason, power companies retain physically favorable water power sites, because even though development is not justified at the time, it may later be advisable because of the growth in firm capacity of the project with the increasing load of the system.

144. Physical Depreciation. — Physical depreciation for hydro electric plants should usually be much less than for steam plants, because the investments in items which are non-depreciable, or which are subject to slow depreciation such as water rights, lands and dams, form a large part of the total investment. It is sound accounting practice to make annual payments to the depreciation reserve, or "reserve for renewals and replacements" as it is more generally called, on a basis of a certain percentage of revenue, thus having the payments larger than the average in prosperous years and smaller in lean years. This money, aside from what is actually used for replacements, stays in the business and earns the same average return as other funds invested in the business, whether such return is credited to the reserve fund or not.

From an engineering standpoint, the purpose of annual depreciation payments and of the depreciation reserve is to have available at all times a fund which may be utilized to replace all items of the development as they wear out and to keep the development as a whole in just as good condition as when new, thus assuring perpetual life. (See also Chapter VI, Section 96.)

Consequently, in economic engineering studies to determine the advisability of making capital expenditures, the sinking fund method of setting up depreciation should be used. In any given case, the annual physical depreciation should be determined item by item for all the items which go to make up the complete development, utilizing the best available estimates for the life of the various items which are comprised in the total. Table 16 gives the estimated life frequently used for the various items of a hydro electric development.

The life of a particular item of cost having been determined, the next thing is to find the annual depreciation payment for that item.

TABLE 16*

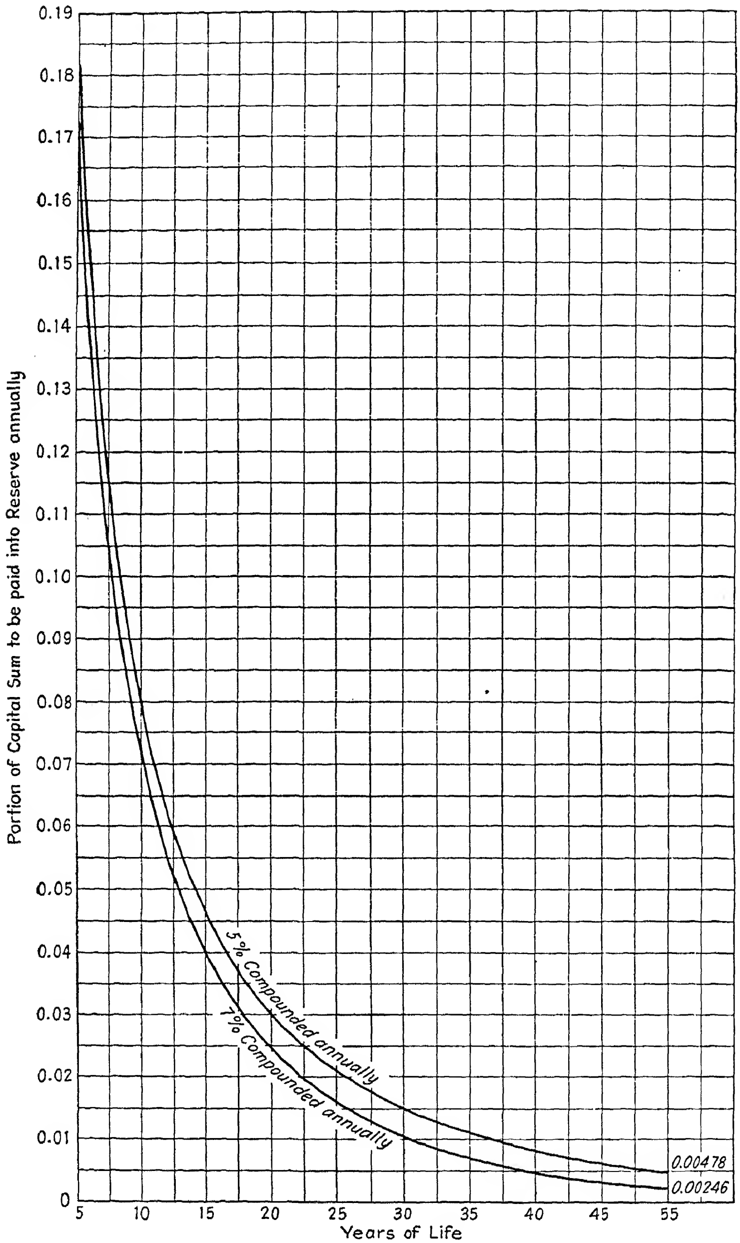
PROBABLE LIFE OF STRUCTURES AND APPARATUS FOR HYDRO ELECTRIC PLANTS

Item	*Life in Years*
Steel bridges	25
Earth dams	†
Concrete dams	†
Timber dams	20
Canals	†
Wooden flumes	10
Steel flumes	20
Concrete flumes	40
Tunnels	†
Steel pipe:	20
Open	25
Buried	20
Wood pipe	20
Concrete pipe	40
Racks	15
Rack structures	20
Concrete substructure	†
Brick and steel superstructures	50
All power house equipment	20
Wood pole lines (copper cost about one-third total cost)	15
Steel tower lines (copper cost about one-third total cost)	30
Outdoor substation structures	25
Outdoor substation apparatus	20
Frame dwellings	25
Metal gates and valves:	
Low-velocity	20
High-velocity	10
Timber gates	10
Exposed gate hoists	15

* From "Hydro-Electric Handbook," page 835, Creager and Justin, John Wiley and Sons, Inc., New York, 1927.

† These items are expected to be kept in perpetual usefulness by proper maintenance and repairs.

The compound interest rate selected should be low enough so that there is no doubt but that the depreciation reserve if invested in the business will be able to earn at least that rate throughout the years of the future. It is common conservative practice to use 5 per cent for this rate. Table 17 is for use in computing the necessary payments to depreciation reserve on account of any given item of the development. Figure 36 gives curves plotted from the data of Table 17.



. 36. Curves for determining annual payments to Depreciation Reserve so that Reserve will equal Capital Cost in given number of years.

TABLE 17*

ANNUAL PAYMENTS REQUIRED TO ACCUMULATE ONE DOLLAR AT END OF A GIVEN NUMBER OF YEARS

Interest Compounded Annually

Number of Years	Interest Rate					
	4%	5%	6%	7%	8%	9%
2	0.497	0.488	0.485	0.482	0.480	0.478
3	0.320	0.317	0.314	0.311	0.309	0.305
4	0.235	0.232	0.228	0.225	0.222	0.218
5	0.184	0.181	0.177	0.174	0.171	0.167
6	0.151	0.147	0.143	0.140	0.136	0.133
7	0.126	0.123	0.119	0.115	0.112	0.109
8	0.109	0.105	0.101	0.098	0.094	0.091
10	0.0834	0.0795	0.0758	0.0724	0.0690	0.0658
12	0.0666	0.0628	0.0592	0.0559	0.0527	0.0496
15	0.0499	0.0463	0.0429	0.0398	0.0368	0.0341
20	0.0336	0.0303	0.0272	0.0244	0.0218	0.0195
25	0.0240	0.0209	0.0182	0.0158	0.0137	0.0118
30	0.0178	0.0150	0.0127	0.0106	0.00883	0.00734
35	0.0136	0.0111	0.00900	0.00724	0.00580	0.00464
40	0.0105	0.00828	0.00647	0.00501	0.00377	0.00296
45	0.00826	0.00627	0.00470	0.00350	0.00259	0.00190
50	0.00655	0.00478	0.00344	0.00246	0.00175	0.00123

* From "Hydro-Electric Handbook," page 836, Creager and Justin, John Wiley & Sons, Inc., New York, 1927.

Assume that we wish to determine the annual depreciation for an item of steel racks costing $1000. From Table 16, it is found that the expected life of such racks is 15 years. Then referring to Table 17 in the 5 per cent column and opposite 15 years (or to Fig. 36), it is found that the rate is 0.0463, that is, the annual depreciation for this item is $46.30 per year. This takes care of physical depreciation, but in addition to this there is the matter of obsolescence.

145. Obsolescence. — Obsolescence should be provided for in connection with every capital expenditure. Obsolescence takes place very slowly in the case of most hydro electric projects, and annual payments to depreciation reserve on account of obsolescence should be very much less for hydro plants than for steam and internal combustion plants.

It is rather difficult for instance to visualize the lands, dams

and riparian rights of a hydro project becoming useless. On the other hand, the authors know of some hydro electric developments in the Piedmont section of the South which originally had ample ponds, but which have now silted up until the pondage has been greatly decreased. The developments still produce power and the dams are still useful in creating head, but it has been necessary to provide pondage regulation by building additional dams upstream. Hence, to that extent, obsolescence has taken place in these developments.

Obsolescence has also taken place in the hydraulic and electrical equipment of many projects, and in the older plants equipment is frequently replaced with more efficient items, and although the changes would not be made unless the savings produced showed a satisfactory return on the new money, a retirement of the capital investment in the old equipment is involved which is not taken care of by the usual plan of making payments to depreciation reserve discussed in the foregoing section, the function of which is to keep the original item of equipment or its duplicate in perfect condition for all time to come. An extreme possibility of obsolescence would be the invention and development of a new source of power supply so much cheaper than either steam or hydro power that both would soon become obsolete.

The authors believe that for every capital investment a means of liquidating such investment should be provided. The result of not doing this is shown by the railroads, whose debts have pyramided and become permanent. In hydro electric developments, there is reason to think that obsolescence will continue to be very slow, and it is recommended that in most cases the liquidation of the total investment be provided for by the sinking fund method over a period of 50 years. From Table 17, with a 5 per cent rate, this would mean laying aside each year for the sinking fund $0.00478 for each dollar of total investment in the hydro development in addition to the sums laid aside to assure perpetual life to the various items of the development as provided for in Section 144.

Annual depreciation and obsolescence computed in the manner advocated above will vary materially for different projects from about 0.7 per cent of total capital cost for projects where the larger portion of the investment is in lands, dams and riparian rights up to about 1.5 per cent for projects where most of the investment is in power house and equipment, but 1.0 per cent

may be taken as a general average which is frequently sufficiently accurate for purposes of preliminary studies. This figure of 1 per cent has been used in illustrative examples involving hydro electric plants in this book, but for any particular case depreciation and obsolescence should be determined in accordance with the principles discussed in this section for obsolescence, and in Section 144 for physical depreciation.

146. Taxes and Insurance on Hydro Plants. — The rate for taxes is generally less for hydro plants than for steam plants. This is because the rate of taxation is less in the rural or backwoods sections where most hydro electric plants are located than it is in the urban or industrial sections where most of the steam plants are located. Insurance is also a considerably smaller percentage of total investment with hydro than with steam, because the total investment in insurable items bears a smaller relation to the total cost.

In all comparative set-ups relating to steam and hydro plants, it is well to eliminate in both cases all the items of total annual cost extraneous to the power plant itself, which cannot affect any decision which might be made. Thus, scarcely anyone would think it necessary or desirable to allocate to the annual cost of such steam and hydro plants any portion of the company's general and miscellaneous expense. Some engineers do, however, allocate to the plants a portion of income taxes and of gross receipts taxes if paid. Although, if the allocation is fairly made, it does not vitiate the comparison, it is usually entirely unnecessary and merely introduces an additional complication into the computation, and should therefore be avoided wherever possible.

An income tax is a tax on profits. Even though the construction of one plant of several alternatives may increase the profits of the company and therefore increase the income tax, this increase in income tax merely means that the company has to give up a part of the increased profit made, and this fact would not keep one from developing the project from which the greatest profit could be made. Consequently, the authors believe that it is better in comparative set-ups of this nature to eliminate any allocation of income taxes to generating plants.

It is practically never necessary to consider franchise and capital stock taxes. Some states collect a gross receipts tax from power companies. This is a tax on revenue. Revenue will not

be affected whichever alternative plant is chosen for development. Consequently in studies of the sort here discussed, it is usually unnecessary to consider such taxes.

Special cases may come up for which such taxes will have to be considered; for instance, one of the alternative plants might be located in a state which collects a gross receipts tax on the output of the plant, whereas at the other alternative project, located in another state, no such tax might be required. Also, in some cases, there may be a license tax of so much per horsepower of installed capacity for developing water power, while no corresponding tax is levied against a steam plant.

In this book it is assumed in the illustrative examples utilized that it is necessary to consider merely those taxes directly applicable to the generating plants, which usually means merely property taxes. On this basis, taxes and insurance on hydro electric plants will generally vary from about 0.5 per cent to 1.5 per cent of total capital cost. In the illustrative cases used in this book, 1.0 per cent has been used for these items, which is believed to be fairly typical.

147. Cost of Money for Hydro Plants. — In the financing of the capital cost of hydro plants, the annual cost of the money raised varies with the credit of the company and the condition of the money market. In the past, some hydro electric projects have been undertaken by independent companies organized for the purpose with the intention of wholesaling the power to various industries and public utilities. In some cases, such companies have had to pay a very high price for money. Ordinarily, however, the construction of hydro electric projects is undertaken only by well established public utilities, or else the enterprise is underwritten by a utility company having a sound credit rating. Consequently, the cost of money required for a hydro project is usually the same as that which the utility company has to pay for money to be used for other capital expenditures. Hence the cost of money for a hydro electric project should usually be just the same as for a steam plant.

However, for any given case, the actual cost of money which will have to be paid should be determined as nearly as may be, and this rate should be utilized in the set-up. This is frequently of material importance, because the amount of money required for a hydro electric plant is usually much greater than that required for a steam plant of the same capacity. If the rate

chosen for use in the comparative set-ups is lower than the actual, it will tend to make the hydro look more favorable than it actually is, and vice versa.

As financing is usually done, the cost of money includes the bond discount and expense, the interest on bonds covering about 50 per cent of the cost, dividends on preferred stock covering 20 to 30 per cent more of the cost and the return on equity money the remainder.

For both steam and hydro plants, the actual total cost of money will in general vary from 5.5 per cent to 8.5 per cent per year of the total cost of the project. In illustrative cases discussed in this book, the cost of money has been taken at 7 per cent per year of total capital cost, which is believed to be fairly typical under normal conditions for companies with sound credit.

148. Total Fixed Charges on Hydro Plants. — Based on the foregoing discussion in Sections 144 to 147 inclusive, the total annual fixed charges on hydro electric plants may be tabulated as follows:

	Usual Minimum Annual Rate, Per Cent	Usual Maximum Annual Rate, Per Cent	Typical Annual Rate as Used in Illustrative Cases in this Book, Per Cent
Total cost of money..........	5.5	8.5	7.0
Taxes and insurance..........	0.5	1.5	1.0
Depreciation and obsolescence .	0.7	1.5	1.0
Total annual fixed charges..... (Per cent of total capital cost)	6.7	11.5	9.0

149. Operation and Maintenance Costs at Hydro Plants. — Annual operation and maintenance costs at hydro plants are more or less proportional to the capacity of the plant and the number of units. Such costs will vary also with the wage scale and the practices of different companies. Actual costs vary widely and are sometimes quite high per kilowatt of capacity for small plants. Thus, there are some plants of 5000 to 10,000 kw capacity where annual operation and maintenance runs from \$4 to \$6 per kw of installed capacity. There are other plants of the same size where the annual cost is less than \$2 per kw. When

due consideration is given to the fact that small plants may be made automatic or may be remotely controlled, it is believed that in general for new plants there is no need of having an annual cost for operation and maintenance (at the plant) in excess of $2 per kw even for plants as small as 5000 kw capacity.

For very large plants of 100,000 to 200,000 kw capacity, the annual cost of operation and maintenance may be as low as 60 to 75 cents per kw of capacity. This applies to new modern plants with large capacity units. Some of the largest hydro plants have developed over a period of years and consequently contain units of varying size and age. Operation and maintenance in such plants are necessarily often very much higher than the figures given below.

Although there is a considerable legitimate variation due to location and type of plant, the following list, based on an examination of records at some thirty plants, giving annual operation and maintenance costs for hydro plants of various capacities, may be taken as roughly typical for a large number of new plants in many sections of the country.

Capacity of Plant, kw	Typical Probable Total Annual Cost of Operation and Maintenance at the Plant	Probable Cost of Operation and Maintenance per kw per Year
10,000	$15,000	$1.50
20,000	25,000	1.25
40,000	40,000	1.00
100,000	80,000	0.80
200,000	140,000	0.70

Such a list as the above is useful only in making preliminary set-ups. As soon as the type of plant, number of units and general arrangement of plant are decided upon, a built-up estimate of this item of annual cost should be prepared. Figure 37 gives a curve based on the same data as the above list showing typical operation and maintenance costs at hydro plants of various capacities.

150. Transmission Liability Against Hydro Plants. — Many hydro electric projects are situated far from the center of gravity of the load which they might supply. In order to utilize them, transmission lines not otherwise required must be constructed.

An alternative steam plant for performing the same function as the proposed hydro would usually be located at or near the load center. Hence in considering the advisability of such a hydro project it is sometimes spoken of as having a " transmission liability." By transmission liability is meant the additional

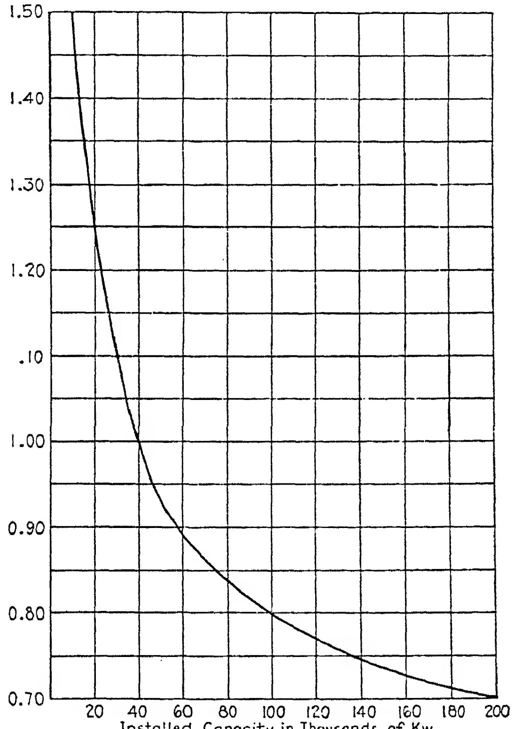


FIG. 37. Operation plus maintenance costs at typical modern hydro plants (based on a study of records of over 30 plants) (from paper on "Economic Balance between Steam and Hydro Capacity" by K. M. Irwin and Joel D. Justin, page 63, Transactions American Society of Mechanical Engineers, Vol. 55, No. 3).

annual cost that will have to be incurred for additional transmission facilities over that which would be incurred if, instead of hydro, steam were added to supply the requirements for increased capacity.

Not all hydro electric projects have this transmission liability. In the case of some territorial companies the large new steam plants are located on rivers where an ample supply of condensing

water is available. Such locations are frequently quite remote from the center of gravity of the system load. In some instances where a hydro electric project is being considered, it is thus found that the alternative steam plant would necessitate as large an annual cost for additional transmission facilities as the hydro project.

There are some other cases where the transmission liability against the hydro is quite small because although the required transmission facilities may be expensive the proposed lines may be used for a dual purpose, as, for instance, interconnection between load centers to secure the advantages of diversity or they may form one leg of a tie line to strengthen the connection between different parts of the system.

This question of transmission liability for any particular hydro project requires careful coordinated study by the electrical and hydraulic engineers and by the engineers charged with system planning. It is of prime importance, because frequently it determines the advisability of a given hydro project. In cases where the hydro project is cheap enough so that it can bear the total cost of independent transmission facilities to the center of gravity of the load, the question is quite simple. However, for the reasons mentioned above, the actual transmission liability may be much less than the total annual cost of such transmission, and its determination in doubtful cases may require a great deal of study.

Under modern conditions the number of hydro electric projects which are cheap enough to stand the cost of, say, 300 miles of transmission are not numerous if the only function of such transmission is to deliver the hydro output to market. On the other hand, if the transmission so provided forms a part of a network tying the load centers and plants of a great regional system together, the transmission liability against the hydro may be small and many such plants may be justified.

For large hydro plants requiring 60 to 150 miles of additional transmission for their sole use the transmission liability may vary from $2.50 to $7.00 per kw per year of installed capacity.

151. Increment Cost of Hydro Installations. — Although the cost of hydro electric developments varies widely and total cost may bear little direct relation to the amount of installation as explained in Section 143, nevertheless certain items of the cost of hydro electric developments are at least roughly proportional to

the installation. In general, these items are intake, conduits, power house and equipment, including substation.

Collectively, this portion of the total cost of hydro electric projects divided by the installation in kilowatts may be referred to as the increment unit cost of hydro electric developments. Thus, if at a certain hydro development the total cost of these items for a 10,000 kw installation were $700,000 or $70 per kw, it is usually a fair assumption that installation might, at the time the project was constructed, have been increased to 20,000 kw at about the same increment cost per kilowatt for the additional 10,000 kw.

Based on confidential information furnished by various power companies and on personal records, a study has been made of these increment costs at existing hydro electric installations. In considering such increment costs, it should be understood that they do not include the cost of dams, lands, riparian rights, reservoirs, highway and railroad changes, etc. On the other hand, they do include the allocated cost of top accounts and overhead.

The data obtained were quite representative. Capacities ranged from 3000 kw to more than 200,000 kw, and heads varied from 32 ft to more than 2000. In general, the unit increment cost of these hydro plants in spite of the wide variation in heads and capacities is about as consistent as the cost of steam plants.

The plants were divided into three classes on the basis of head, as follows: Low heads, below 100 ft; medium heads, 100 to 500 ft, and high heads, above 500 ft.

For the low head plants, head varied from 32 to 90 ft and capacities from 3000 to over 200,000 kw. All except one of these plants showed an increment cost below $65 per kw of installed capacity, the minimum increment cost being $53 per kw. The highest increment unit cost was for the plant having a 34 ft head and 3000 kw capacity and was $117 per kw. This higher increment is not representative for plants of this size and head as it included costs which are not usually incremental.

The medium head plants (100 to 500 ft) had heads ranging from 190 to more than 350 ft and capacities from 4000 to 45,000 kw. Increment costs per kilowatt in this group varied from slightly below $50 to slightly above $110 per kw.

High head plants having heads in excess of 500 ft had installations ranging from 50,000 to 100,000 kw and unit increment costs

ranging from slightly less than \$70 per kw to more than \$150 per kw.

A study of the data collected leads to the following conclusions: There is no marked relationship between head, capacity and unit increment cost of installation. (Some of the low head small capacity plants are among those showing the lowest unit increment installation costs.)

It would appear that at many low head hydro electric projects it is feasible to increase the installation at the time the project is built at an increment cost of \$55 to \$70 per kw for such additional installation. The same statement appears to apply equally well to plants of medium head (100 to 500 ft).

With regard to high head plants some reservations must be made. Many high head plants have been designed and built for high load factor operation, the conduit, flow line and penstock, sometimes of great length, being continuous from the source of water supply to the power house. What has herein been termed increment cost would be high for such a plant because it includes such a large proportion of the total cost of the project. On the other hand, where the project may be designed with a flow line conduit for continuous operation discharging into a regulating pond of sufficient size for pondage, with relatively short penstocks leading from here to the power house, the cost of flow line conduit is eliminated from increment costs and in such a case the increment cost may be of the same order as those for other classes of plants or from \$55 to \$70 per kw.

152. Increment Cost of Installation at Existing Hydro Electric Plants. — In existing hydro electric plants the increment cost of installation may be very different from the increment cost in new plants. This is because in some cases a far sighted design has provided in advance for additional installation whereas in others no provision has been made and the design and construction are such as to make additional installation very expensive. In many existing hydro plants, however, additional capacity might be installed at about the same cost per kilowatt as given in the previous section for unit increment costs for new installations.

153. Importance of Increment Cost of Hydro. — The importance of the increment cost of hydro installation as a factor affecting the economics of hydro electric plants has not always been fully realized. For instance, at a given site it was determined after investigation that a proposed 10,000 kw hydro

plant could be constructed at a total cost of \$3,000,000 or \$300 per kw. This cost is high, and it will be assumed that additional steam capacity could be installed to furnish power and energy more cheaply.

The pond at this site would be of ample proportions, and it was found that if the capacity were doubled the total cost of the 20,000 kw project would be \$3,700,000 (increment cost of installation \$70) giving a total unit cost of \$185 per kw. The investigation showed that the 10,000 kw plant would be firm on the connected load curve and that two years hence the 20,000 kw plant would be firm capacity on the connected load curve. Also, owing to the fact that the larger plant would utilize a larger proportion of the total river flow, the 20,000 kw plant would have an annual output of energy about 25 per cent in excess of the smaller plant. On this basis it was found that when the 20,000 kw plant would be firm capacity, and hence could have credited to it full capacity value, it would be a cheaper source of power and energy than an alternative steam plant. Consequently, instead of the project being reported on adversely, the site was purchased and held for future development.

A simplified set-up for the two cases will now be given. For both cases, annual cost of alternative steam power was \$17.25 per kw for capacity and 2 mills per kwhr for energy.

Case 1 : 10,000 kw Hydro

Capacity firm on load curve at time of installation.

Note that alternative steam plant is identical with that represented by curve A_2, Fig. 38.

Gross Annual Revenue on Basis of Steam Value

10,000 kw @ \$17.25		\$172,500
(10,000 kw is firm capacity)		
50,000,000 kwhr @ 2 mills		100,000
(average year)		
Total gross revenue creditable to hydro		\$272,500
Deduct total annual cost of hydro		
Fixed charges @ 9 per cent on \$3,000,000	\$270,000	
Operation and maintenance from Fig. 37	15,000	285,000
Net annual loss on hydro as compared to alternative steam		\$ 12,500

Case 2 : 20,000 kw Hydro

At same site as Case 1, to be built two years hence when the capacity will be firm on connected load curve.

Gross Annual Revenue on Basis of Steam Value

20,000 kw @ $17.25		$355,000
62,000,000 kwhr @ 2 mills		124,000
Total gross annual revenue creditable to hydro		$479,000
Deduct total annual cost of hydro		
Fixed charges on $3,700,000 @ 9 per cent	$333,000	
Operation and maintenance from Fig. 37	25,000	358,000
Net annual advantage of hydro as compared to alternative steam		$121,000

The above comparison assumes no transmission liability against hydro as compared to steam. Chapter XI, Section 161, discusses the effect of increasing installation on the economic feasibility of certain hydro projects.

154. Significance of Incremental Cost of Hydro Installation. — In a paper, "Economic Balance between Steam and Hydro Capacity," by K. M. Irwin and Joel D. Justin, presented at the Bigwin, Canada, meeting of the American Society of Mechanical Engineers, June 27, 1932, and published by the Society in their Transactions, Vol. 55, No. 3, page 63, there was a figure which illustrated in a graphic manner the significance of the incremental cost of hydro capacity. Figure 38 herein is based on some of the same data modified to agree with other illustrative examples used herein, and with further data added to show the effect of different prices for coal.

In Fig. 38, curves A_1, A_2 and A_3 give the total cost of energy at various annual capacity factors for a modern steam plant having a capital cost of $100 per kw with fixed charges of 13.5 per cent and 14,000 Btu coal. Curve A_1 is for coal at $5.00 per net ton with a fixed component of operating of $3.93 per kw and a variable production cost of 2.55 mills per kwhr. Curve A_2 is for coal at $4.00 per net ton with a fixed component of operating of $3.75 per kw and a variable production cost of 2 mills. Curve A_3 is for coal at $3.00 per net ton with a fixed component of operating of $3.57 per kw and a variable production cost of 1.57 mills per kwhr.

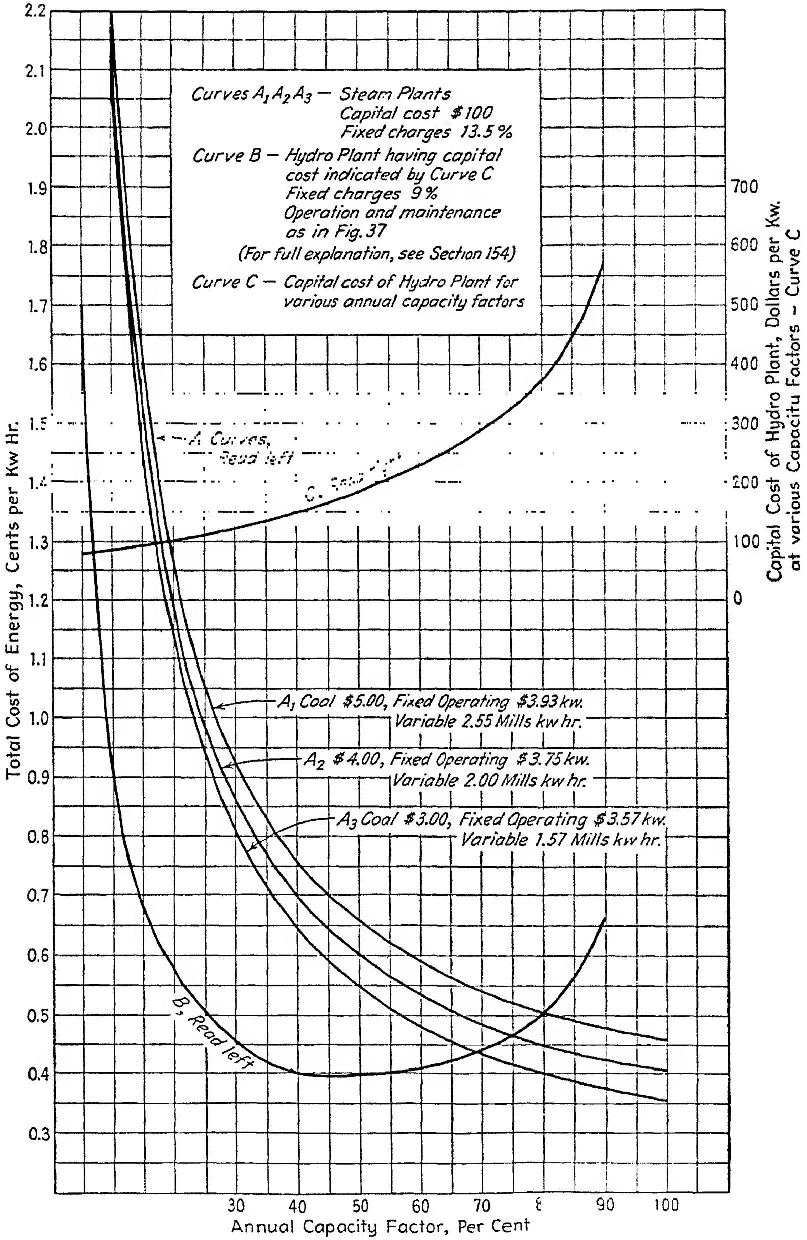


FIG. 38. Total unit cost of energy for various annual capacity factors at steam and hydro plants. (For full explanation see Section 154.)

"Curve C[7] gives the total capital cost per kilowatt of installation for a hydro plant if installed for various annual capacity factors. The plant is a fairly typical hydro plant on a fairly typical American river, having an average annual run-off of about 1.5 cfs per square mile and a range of flow varying from a weekly minimum of 0.15 cfs per square mile to more than 28 cfs per square mile. Thus the larger the installation, the greater the amount of energy turned out by the plant during any given year. It should be remembered, however, that the annual capacity factor of a hydro plant decreases with increased installation. The plant has ample pondage for weekly regulation, which is a prime requisite for any hydro project if all its capacity above that required for minimum stream flow is ever to become firm on the load curve.

"In order to arrive at the capital cost per kilowatt of installation for various capacity factors, an actual operating modern plant on this river was selected. The actual total costs were segregated in items which would be the same regardless of installation, such as lands, water rights, dams, railroad changes and highway, and the items which vary with the amount of installation, such as power house, equipment, turbines and transmission. This latter group constitutes the increment cost of installation and was found to be approximately \$70 per kw. Starting with an installation which gives 100 per cent capacity factor (or that required to just utilize the minimum weekly flow), the installation was increased by increments and the capacity factor and cumulative cost determined for each increase in installation. To get the unit cost, the total was divided by the total installation.

"Curve C then shows for a fairly typical case the tremendous variation in unit capital cost of hydro according to the amount of installation installed. Thus, if the project is planned on a 90 per cent annual capacity factor basis, the capital cost would be about \$580 per kw, whereas if planned on a 20 per cent annual capacity factor basis, the capital cost would (by curve C) be about \$100 per kw. It should here be noted that, in order to be firm capacity on such a low capacity factor basis, it would probably be necessary for the connected load to be three or four times the installed hydro capacity, and thus the load

[7] Quotations are from the paper by Messrs. Irwin and Justin mentioned in this section.

would absorb all hydro energy generated. The curves are applicable only for the case where all hydro capacity installed would be firm capacity on the load curve. In fact, it seldom pays to consider hydro installations on a low capacity factor basis unless all the capacity is firm.

" In order to obtain curve *B*, it was necessary to obtain the amount of energy available for the installation required to give the various capacity factors. For this purpose, flow and power duration curves of the fairly typical stream selected were utilized."

The fixed charges on the hydro plant were taken at 9 per cent as in the other illustrative examples in this book, and the operation and maintenance charges were taken from the curve in Fig. 37. Total annual cost per kilowatt, including fixed charges and maintenance and operating, were divided by the energy output per kilowatt, and thus the total cost of energy for various capacity factors determined. In determining operation and maintenance costs, it was assumed that installation at 100 per cent capacity factor would be 10,000 kw. Curve *B* indicates that at low capacity factors there is typically a material advantage in hydro, but that at very high capacity factors that advantage is lost, as the curve rises rapidly after a capacity factor of 60 per cent is exceeded.

Not all hydro electric projects would show a curve of the same form as curve *B*, Fig. 38, and if the hydro plant derives its water supply by diversion of a part of the minimum flow of the stream, like the Niagara plants, without the necessity for expensive dams, the total cost per kilowatt-hour may be very low. Curve *C* for such a project might be almost a horizontal straight line. Plants on well regulated streams may also sometimes be installed for high capacity factors and have a much lower total cost per kilowatt-hour. In any specific cases, values will be different from those here plotted to represent a fairly typical example, but it is often very helpful to plot curves for particular projects like those of Fig. 38 to aid in making the most economical decision.

It is recognized that some hydro enthusiasts may study Fig. 38 and note that, even with $3 coal, the steam plant must operate at an annual capacity factor of at least 69 per cent in order to have the total cost per kilowatt-hour as low as that of

the hydro. The hydro enthusiast might then maintain that, inasmuch as steam plants could not be expected to operate at such high capacity factors very long,[8] there just was nothing to it, and he might then claim that Fig. 38 proved that hydro was typically cheaper than steam power.

However, the hydro enthusiast would be missing the most important element in the whole situation. The basic assumption of the entire discussion in this section was that all the hydro capacity installed is firm capacity. It is only because it is firm capacity that the results shown in Fig. 38 may be achieved. Under most conditions, it would not be firm capacity unless a very large portion of the load curve was supplied by steam capacity.

Hence Fig. 38 does not indicate that either steam or hydro is cheaper, but it does show that under typical conditions the total cost of power will be less in a system served by both types of plants with some of the hydro plants working at low capacity factor and taking care of the upper portion of load curve which has a very low load factor.

[8] See Fig. 39.

CHAPTER XI

VALUE OF HYDRO ELECTRIC POWER

155. Component Parts of Value of Hydro Power. — The value of hydro electric power may be divided into two components: energy value and firm capacity value, or merely capacity value as it is more generally referred to because there is no capacity value unless the capacity is firm capacity.[1] As previously shown,[2] steam is the yardstick by which the value of hydro electric power and energy must be measured. The reason for dividing the value of hydro power into these two components is that each of them has its counterpart in steam plant practice.

156. Capacity Value. — As shown in Chapter VI, Section 103, the annual total cost of any given steam plant may be divided into (1) fixed charges per kilowatt of capacity, (2) fixed cost of operating per kilowatt of capacity, (3) peak prepared for cost per kilowatt and (4) variable cost of operating, usually stated in mills per kilowatt-hour. For comparative purposes, when considering an alternative hydro plant, the first three items are usually combined and designated the annual capacity cost, thus giving the capacity value for the alternative steam plant.

Whenever a capacity value per kilowatt is computed and applied to a proposed hydro electric project, it is tacitly assumed that the alternative steam plant which would otherwise be constructed would have a capacity equal to the firm capacity of the proposed hydro electric plant. Occasionally this is impracticable, and if a steam plant were constructed, it might be either of very much greater or very much less capacity than the firm capacity of the proposed hydro electric plant. In such cases, it is necessary to look further ahead and make parallel computations of the total annual cost of power supply to the system for a number of years in the future for the construction of either alternative.[3]

Such computations are frequently desirable in connection with precise determinations, but for preliminary set-ups, it is usually sufficiently indicative to compute and utilize capacity value on

[1] See Chapter IX, Section 138.

[2] See Chapter IX, Section 131.

[3] See also Chapter I, Sections 13 and 14.

the basis of the same amount of capacity for either alternative. In most of the illustrative examples used in this book, it has been assumed that an alternative steam plant would have a capital cost of $100 per kw, that fixed charges[4] would be 13.5 per cent and that the fixed cost of operating plus peak prepared for cost would be $3.75 per kw with 14,000 Btu coal at $4.00 per net ton, giving a capacity value for an alternative hydro plant of $17.25 per kw of firm capacity.

157. Energy Value. — The unit value of the energy which a hydro electric plant can produce from the available stream flow and which can be absorbed into the system is the same as the increment cost of energy (or variable cost of operating) which would obtain at the alternative steam plant. This statement is not always precisely true, however, and the exceptions are discussed in the next section. In the illustrative examples utilized in this book, a coal cost of $4.00 per net ton for 14,000 Btu coal has generally been assumed as giving an increment energy value of 2 mills per kwhr.

158. Value of Hydro Energy May Differ from the Increment Cost of Steam Energy. *Cases in Which Value of Steam and Hydro Energy Are the Same.* — It has been assumed above that the value of the output of a hydro electric plant would be determined by the annual capacity cost and the increment cost of energy at an alternative steam plant. In a system containing several steam plants having various increment costs of energy, this is precisely true if the hydro plant would operate at the same average annual capacity factor as the alternative steam plant. This would also be true if all the steam plants in the system were equally efficient, regardless of whether or not the proposed hydro plant had the same annual capacity factor as the alternative steam plant. If the overall efficiency curve for steam plants is close to reaching the limit of maximum efficiency, as many steam plant engineers believe, then, after the old inefficient steam plants are replaced, all the steam plants in any given system will have approximately the same increment cost for energy, and the annual capacity factor on an alternative steam plant will make no difference in the value which should be assigned to energy produced by a proposed hydro electric plant.

Annual Capacity Factor of Hydro Remains Constant. — A hydro plant, though subject to the more or less fortuitous varia-

[4] See Chapter VI, Section 93.

tion in annual stream flow, operates over a term of years at the same average annual capacity factor, provided the system is large enough so that all the energy which the plant can generate may be absorbed in the system, and it will keep on doing this indefinitely.

Annual Capacity Factor of Steam Plant Declines. — On the other hand, when a new steam plant is constructed, it is usually the most efficient steam plant in the system and may be intended to operate on the base of the load curve at an annual

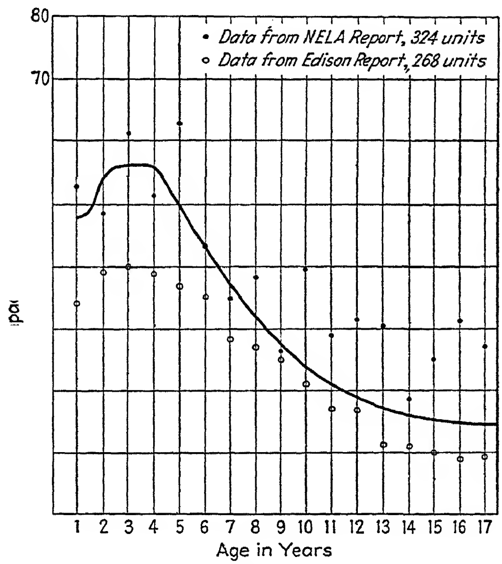


FIG. 39. Effect of age on annual capacity factors of steam plants. (Based on data from report on turbines, Prime Movers Committee, National Electric Light Association, Publication No. 151; also minutes of 42nd Annual Meeting, 1925, Association of Edison Electric Illuminating Companies, V. E. Alden in report of Committee on Power Generation.)

capacity factor of perhaps 60 per cent, displacing energy which would otherwise be generated at higher cost in the older steam plants. Figure 39, which is based on detailed operating records of a large number of steam turbine units, shows the effect which age has had on the annual capacity factors obtained in the past. The curve indicates that, on the basis of experience, one may expect a new steam plant to operate at or near an annual capacity factor of about 50 per cent during the first year and a half, after which the capacity factor may be expected to rise rapidly to

about 56 per cent, where it may be expected to remain until about the expiration of the fifth year, after which the annual capacity factor may be expected to decline rapidly, as indicated by the curve, until it reaches about 16 per cent by the fourteenth year of service.

It should be remembered that the points plotted in Fig. 39 are averages for a large number of units, and that the expectancy curve shown is intended merely to indicate the annual capacity factor which a unit of various ages may be expected to have. Under some circumstances, certain units may have considerably higher annual capacity factors.

Effect of Capacity Factor on Comparative Value of Hydro Energy. — From the above discussion, it would appear that, on the basis of experience, the average annual capacity factor throughout its life which may be anticipated for a steam plant is about 32 per cent, which is the point given by the curve on Fig. 39 for an age of eight years. This also checks fairly well with the assumption discussed in the first paragraph of this section, namely, that the overall efficiency of steam plants has very nearly reached its maximum limit. If that assumption is correct, then, as the older plants are replaced, a condition will be approached where the annual capacity factor of every steam plant will closely approximate the annual capacity factor for the system (every plant being equally efficient). Thus, while the average annual capacity factor for the whole country is now 30 per cent as shown in Fig. 4 (Chapter II), there is reason for thinking, as discussed in Chapter II, Section 17, that this is due to a temporary surplus of capacity and that an average annual capacity factor of 37 per cent is practicable.

In view of the considerations discussed above, it is believed that for comparative purposes an average annual capacity factor of 40 per cent should be assumed in most cases for proposed steam plants when considering a hydro electric project as a possible alternative. Then if the proposed hydro plant had an annual capacity factor of less than 40 per cent the hydro energy would be worth less than the increment cost of steam energy, but on the other hand if it had a capacity factor greater than 40 per cent it would be worth more than the increment cost of steam generated energy.

Example Showing Variation in Comparative Value of Hydro Energy. — Just as an example, it will be assumed that a 100,000

kw hydro plant is proposed. The entire capacity would be firm on the load curve and the plant would produce in the average year 390,000,000 kwhr. The alternative steam plant would have an incremental energy cost of 2 mills, whereas the best present steam plants in the system have an incremental energy cost of 3 mills. Investigation shows that, initially, the new plant could operate on a 65 per cent annual capacity factor producing 570,000,000 kwhr per year or 180,000,000 kwhr more than the proposed hydro plant. This additional energy would go to replace the 3 mill energy of the older steam plants, the differential saving being 1 mill per kwhr or a total of $180,000 per year.

Now then, the capacity value for both steam and hydro is the same. Consequently, in order to have the total cost of power supply the same in either case, it follows that if the hydro is added instead of steam, the total value of the hydro energy must be $180,000 less than the cost of the same amount of energy produced by the alternative steam plant. Therefore, in this case, the unit value of the energy produced by the hydro plant would be 2 mills minus ($180,000 ÷ 390,000,000 kwhr) = 1.54 mills per kwhr during the early years of operation. This, however, would hold only so long as the 65 per cent annual capacity factor on the alternative steam plant was maintained. As new steam plants are added, the capacity factor on the plant considered would decrease until within about six years it would be about the same as that of the alternative hydro or 45 per cent, as shown by Fig. 39. At this point, the value of the hydro energy would be 2 mills.

Thereafter, with the increasing age of the steam plant, its annual capacity factor would decline and the hydro would have the advantage, and thus the relative unit value of the hydro energy would increase.

It is not usually necessary to follow the variation in the value of hydro energy from year to year with the declining capacity factor of the alternative steam plant in the precise manner discussed above, but there are some cases in which such a course is advisable.

159. Size of Proposed Plant Important in Determining Immediate Feasibility. — The size of the plant which may advisedly be installed is often an important factor in determining whether the next increment of capacity should be steam or

hydro. Thus, in a system having a load of 150,000 kw, additional capacity was required. A 60,000 kw steam unit was proposed. It would have required four years of growth to load up this unit, during which period interest charges on the unused investment would have piled up. There were available in the territory several sites where hydro plants of 10,000 to 20,000 kw capacity could be installed and be firm capacity at the time of installation. Consequently, hydro plants were installed in increments about equal to the annual growth in load, and heavy interest charges on unused investment were avoided.

Often, it is the proposed hydro plant which it would require a number of years of growth to load up. The Conowingo project, for instance, had to wait a generation before it became economically feasible to develop it.

It is, of course, not usually practicable to determine capacity value and energy value based on a 60,000 kw steam plant and then apply these factors to determine the economic advisability of a 10,000 kw hydro plant.

In most cases, where the size of alternative plants would be materially different, it is desirable to estimate the total annual cost of power supply for four or five years in the future, omitting from consideration all fixed charges on capital investment already made, but including all fixed charges on additional investment. Two complete sets of computations should be made, one for the case where the steam plant is added, and one for that in which the hydro plant is added. Sometimes several alternative programs are involved, representing as many sets of computations for various combinations of proposed plants. Such a study should be projected forward to the time when the alternative plant having the largest proposed installation will become fully loaded, as it sometimes happens that a large plant produces large operating savings the effect of which is not fully evident until the plant is loaded up.

In such cases, it is necessary to work out load duration curves for typical weeks of each month of the years to be considered, and then allocate the existing and proposed plants to serve the load curve in the most efficient manner. Although future loads and actual allocation of plants to the loads may turn out to be quite different from those assumed, such computations, if properly made, will show in a very conclusive manner the relative total annual cost of power supply each year under the various

alternatives. That scheme which on the average shows the minimum total annual cost of power supply is the one which should be adopted.

160. Economic Analysis of a Typical Hydro Project. — It will be assumed that in a certain hydro project thorough field investigations, office studies and estimates have been made, and it has been determined that 100,000 kw of capacity may be installed at the site and be firm capacity on the connected load curve in the year that the project will be completed. The pondage available is ample for weekly regulation with only slight drawdown. The minimum amount of energy available during a peak load week has been determined as 4,000,000 kwhr, which means that during such a week the plant would operate at a capacity factor of 23.8 per cent. The feasible output of the plant in the average year has been determined as 480,000,000 kwhr, giving an average annual capacity factor of 55 per cent.

The growth of load in the system is such that about 100,000 kw of additional capacity will be required in the year in which the proposed hydro project can be completed. Although not more than 100,000 kw of capacity at this hydro project could be firm at the time the project is completed, it is evident that the characteristics of the project make it suitable for additional installation some time in the future, and, accordingly, provision has been made in the design so that this may be readily done. The total capital cost of the project has been estimated at $17,500,000, exclusive of transmission.

A careful study has been made relative to the transmission liability of the project along the lines discussed in Chapter X, Section 150, and it has been determined that in order to be comparable to the alternative steam plant, it will be necessary to charge against the project the cost of transmitting its output to a secondary load center 60 miles from the plant, from which point the output will be distributed in various directions over existing facilities. The cost of the additional transmission facilities required which (although they may have some future additional function) must be charged against the hydro project has been estimated as $3,100,000. Taking total annual cost on transmission as 15 per cent gives an annual transmission charge of $465,000. This gives a transmission liability against the project of $4.65 per kw per year of installed capacity.

The alternative steam plant would be located at or near the

above secondary load center, and its annual cost has been determined as $17.25 per kw per year for capacity and 2 mills per kwhr for energy.

As the losses in transmission have been determined as 6 per cent on capacity at time of full demand and an average of 4 per cent in energy, the hydro power delivered would be $0.94 \times 100{,}000 = 94{,}000$ kw and the hydro energy delivered would be $0.96 \times 480{,}000{,}000 = 460{,}800{,}000$ kwhr.

Based on the above data and assumptions, a set-up for the project may now be made.

A. Annual Value of Hydro Power Delivered in Average Year (based on costs at alternative steam plant)

94,000 kw delivered @ $17.25	$1,621,500
460,800,000 kwhr delivered @ 2 mills	921,000
Total annual value of hydro power	$2,542,500

B. Annual Total Cost of Hydro Power Delivered

Fixed charges on hydro development as in Chapter X, Section 148, 9 per cent on $17,500,000	$1,575,000
Operation and maintenance of hydro plant (see Chapter X, Section 149)	80,000
Total annual cost of transmission (see above)	465,000
Total annual cost of hydro power delivered	$2,120,000

Hence, in this case, the annual advantage of the hydro plant over the alternative steam plant is $2,542,500 − $2,120,000 = $422,500 per year. This would usually be considered quite a satisfactory margin when consideration is given to collateral advantages discussed in Section 162 and to the fact that, when required, additional capacity can be added quite cheaply. The alternative steam plant used as a bogey is a 400 lb plant having a capital cost of $100 per kw. Fixed charges are taken at 13.5 per cent; 14,000 Btu coal costs $4.00 per net ton; the fixed cost of operating is $3.75 per kw, and variable operating is 2 mills per kwhr. The hydro plant discussed is not an unusually cheap project, as the total cost $\frac{\$17{,}500{,}000 + \$3{,}100{,}000}{94{,}000 \text{ kw}} = \$220$ per kw.

It is believed that the above method is preferable to any attempt to figure "the return on the investment" (which is

necessarily a more or less theoretical figure) because it answers the question in which the power company is really interested, namely, "Which source of power supply is the cheaper under the given condition?" When the return on the investment is required, it is frequently obtained by using the present average cost of steam power as the criterion. The return on the investment for a case like the above, on this basis, often works out to

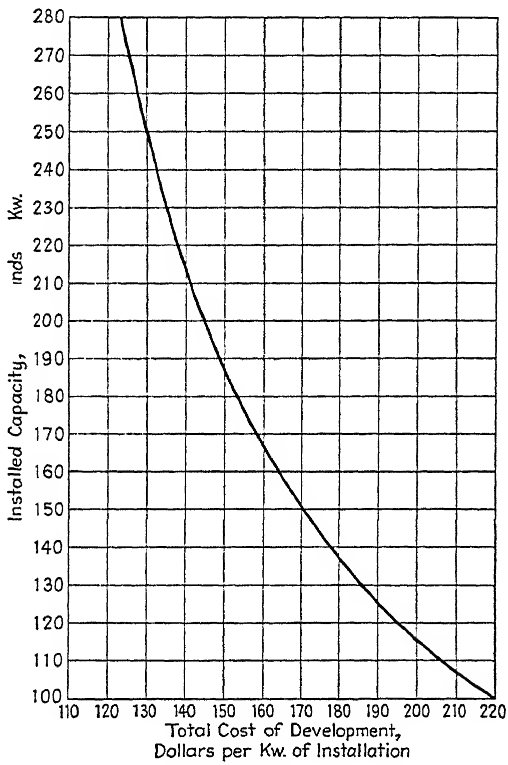


FIG. 40. Effect of increasing installation at a hydro electric development similar to that in Section 161 on the total unit capital cost of the project.

a very high figure, but it proves very little because a more efficient steam plant might fulfill the same functions more cheaply.

Quite frequently, however, a public utility executive charged with making the decision as to whether or not to build the hydro plant discussed above would look at the problem in the following manner: $9,400,000 must be spent for a steam plant to take care of the increasing load. If, however, a hydro plant is built

instead, the required capital expenditure would be $20,600,000 (including transmission) or $11,200,000 more money than required for a steam plant. What return will the power company get on this excess investment?

This question can be answered from the data already given as follows:

Annual Cost of Delivered Hydro Power Excluding Interest on Excess Investment in Hydro

Depreciation, taxes and insurance on hydro development (Chapter X, Section 148) 2 per cent on $17,500,000	$350,000
Operation and maintenance on hydro plant (Chapter X, Section 149)	80,000
Operation, maintenance, depreciation, taxes and insurance on transmission facilities, 8 per cent on $3,100,000	248,000
Interest charges on cost of alternative steam plant, 7 per cent on $9,400,000	658,000
Total annual cost of delivered hydro exclusive of interest on excess investment of $11,200,000	$1,336,000

Annual sum available for return on excess investment

$2,542,000 minus $1,336,000 equals $1,206,500.

Return on excess investment in hydro

$\frac{1,206,500}{11,200,000}$ equals 10.7 per cent.

As this rate is considerably in excess of the average net return on public utility property, it indicates the advisability of the investment.

161. Effect of Increasing Installation on Feasibility of Certain Hydro Projects. — In order to illustrate the effect of increasing installation on the feasibility of some hydro projects with ample pondage, the same project as in Section 160 will be utilized but with the following difference. It will be assumed that instead of an estimated cost of $17,500,000 for the hydro project, further investigation shows that the project will cost $22,000,000. Figures 40 and 41 have been prepared on this assumption. Additional capacity can be added at this project at a cost of $70 per kw (see also Chapter X, Sections 151 and 152), and Fig. 40 shows the effect of adding various amounts of capacity on the

total unit capital cost of the development. Thus, for an installation of 100,000 kw, the project will cost $220 per kw, but for one of 280,000 kw it will cost only $123 per kw.

Figure 41 shows the effect of increasing installation in reducing the annual unit capacity cost. For the 100,000 kw plant, the annual capacity cost is $12.40 per kw. If $5.00 per kw per year is the transmission liability (in this case including losses), the

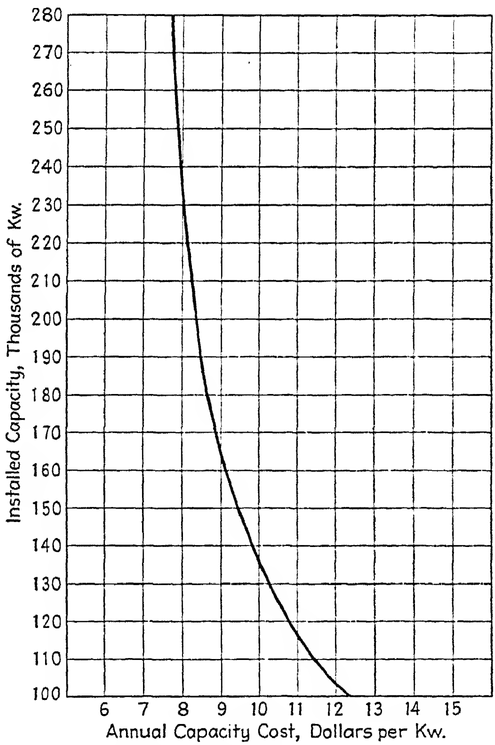


FIG. 41. Effect of increasing installation at a hydro electric development similar to that in Section 161 on the annual capacity cost per kw of firm capacity.

cost of the capacity delivered would be $17.40 per kw year. On this basis, the construction of the project might not be advisable. However, as is indicated by Fig. 41, the best thing to do with the project is not to abandon it, but simply to delay its construction until such time as a larger amount of capacity can be installed and be firm capacity on the connected load curve. Thus, when 140,000 kw can be installed as firm capacity, the

annual capacity cost at the plant would be $9.88 per kw and the annual capacity cost per kw delivered would be $14.88 (assuming $5.00 per kw year as transmission liability) as compared to $17.25 for the alternative steam plant. From this point on, Fig. 41 shows that further additional installations when firm would be increasingly profitable in comparison with the alternative steam plant.

In an actual case, it would also be necessary to determine whether or not a very low capacity factor hydro plant would have some liability during the early years of operation due to the ability of the alternative steam plant to generate more energy than the hydro. This is more fully considered in Section 158.

162. General Advantage of Having Some Hydro Capacity in System. — In any given power system there are advantages in having a certain portion of the total installed capacity in hydro electric plants, which, however, cannot always be evaluated in dollars.

In a system where some hydro capacity backed up by ample pondage or storage is available, it is not necessary to keep as many boilers hot or as many steam units hot and turning over unloaded or inefficiently loaded as is the case in a 100 per cent steam system. This is because the hydro can quickly take any increase in load, permitting the steam units to be operated at or near maximum efficiency.[5] Even with boilers hot, it takes a large modern steam turbine an hour or more starting cold to be warmed up and put onto the line at full load. On the other hand, a hydro unit can go from standstill to full load in one to three minutes.

Recently a balloon descended on and completely severed the transmission lines leaving a 150,000 kw steam plant. Other steam units turning over in the system were of insufficient capacity to pick up the load, but the system was interconnected with a hydro plant of large capacity located 160 miles away. The units at this hydro plant immediately opened up and took on this load. Had it not been for the hydro plant, a large amount of load would have been dropped until additional steam units in other plants could have been warmed up and placed on the line.

Another very useful incidental function which many

[5] This would not be true during the relatively brief periods when all hydro plants had available water supply equal to maximum plant discharge.

plants perform is power factor correction. The value of this service is to a considerable extent dependent on the location of the hydro plant relative to the loads of the system. It is common practice to utilize hydro electric units when not in demand as synchronous condensers for power factor correction, and in some cases it has been possible to determine approximately the value of the service thus performed in dollars and cents.

Many hydro plants may be utilized for peak load operation, cutting off the sharp peaks of the load curve which are expensive to carry on steam and thus permitting the steam units on the line to operate at more efficient loading. Peak load hydro plants with reservoir intakes are well suited for daily operation on this basis. Run of river plants with ample pondage are also used for this purpose during the low water season.

The general advantages of having some hydro capacity in a power system are apparent if Fig. 42 is examined. This is the load curve for a peak load winter day of a territorial power company having a preponderance of urban and industrial load. It will be noted that the top 20,000 kw of the load curve (area *A*) is supplied from a peak load hydro plant having a large reservoir and an installed capacity of 40,000 kw in two units of 20,000 kw each (propeller type runners with adjustable blades are used to obtain high efficiency at any loading). One of these units is operating on load, the other is turning over as a synchronous condenser to improve power factor, but is ready to go on the line instantly to furnish breakdown service for steam or hydro units that might go out for any reason.

The requirements of area *B*, the next band down on the load curve, are being met on this day by the company's run of river hydro plant which has an installation of 30,000 kw, together with ample pondage. The day in question is one of about average river flow, but the flow has been ponded to concentrate the operation of the plant into the area *B*.

The band represented by area *C* is supplied by the company's old steam plant of the vintage of 1918. This plant has two 10,000 kw units both operating, but total load being carried is 15,000 kw.

The base of the load area *D* is being carried by the company's new steam plant built in 1930. In this plant, there are two 20,000 kw units, but loading totals 35,000 kw to obtain maximum efficiency.

The allocation of the plants to positions on the load curve will not be the same for all days, but is carried out to secure minimum production cost for the different conditions of load and stream flow. Thus, on a day when the load curve is practically identical to the above, but when stream flow at the run of river plant equals

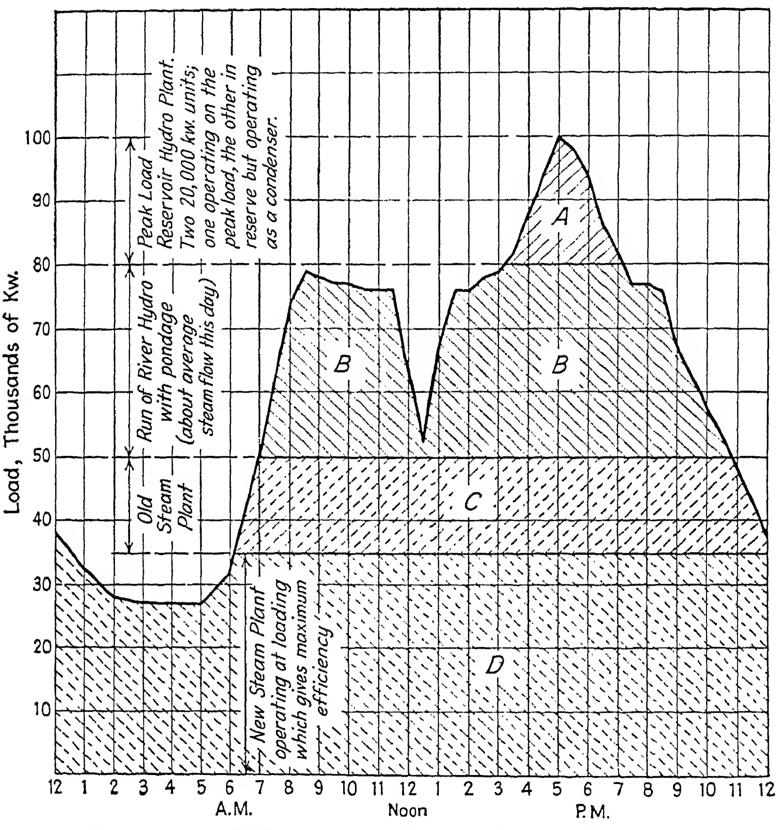


FIG. 42. Load curve for January peak day 1933, Blank Power Company, showing allocation of steam and hydro plants.

or exceeds plant capacity, then the run of river plant would occupy approximately the base load band D and the new steam plant would move up on the load curve and occupy approximately the band C and the old steam plant would move up into approximately band B. Again, in August or September, when loads and stream flows are apt to be low, it may become desirable to conserve the water in the reservoir of the peak load

hydro plant for the peak load period, and at that time either the run of river hydro plant or the old steam plant may occupy the band which includes the peak of the load.

The daily allocation of a group of steam and hydro plants to the system load curve to secure at all times the minimum production cost under the varying conditions of load and stream flow is both an art and a science. (See also Chapter XIII.)

CHAPTER XII

PEAK LOAD PLANTS

163. Problem of Carrying Peak Loads. — In spite of much effort and the many methods devised to produce high annual system load factors, those appreciably greater than 50 per cent are seldom encountered. Low load factors mean long hours with little or no generation on the part of a large portion of steam capacity. Figure 43 is a load duration curve of a system having an annual load factor of 47 per cent. An inspection of this curve shows that, of the capacity required to supply it, one-half is in service 4161 hours and supplies only 17.5 per cent of the total kwhr and 30 per cent is in service only 1533 hours and supplies only 3 per cent of the total kwhr.

The load factor of the upper 50 per cent of the load is only 16.5 per cent, and of the upper 30 per cent of the load only 4.65 per cent. Because of this short hour use of capacity, this portion of the load is the most expensive to supply. Thus, the total annual cost of supplying the upper 30 per cent of the load curve shown in Fig. 43 from a modern steam plant might be 4.6 cents per kwhr[1] without considering the cost of reserve requirements.

The reader is also referred to Fig. 38 which gives typical total unit costs of energy for various capacity factors for both steam and hydro plants.

164. Old Steam Plants for Carrying Peak Loads. — Unless peak load hydro power is available, this duty is usually assigned to the older steam stations in the system. This has been brought about by growth in load and development of more efficient methods of generating steam power. As loads grew, new plants were built, at little or no increase in capital cost over the old, which were much less expensive to operate than the existing plants.

Large savings were possible not only in fuel costs, but also in labor costs. These new plants were operated on the base of the load at high capacity factors in order to obtain maximum bene-

[1] Assumes fixed charges @ \$13.50 per kw per year; fixed cost of operating, @ \$3.00 and variable cost of operating @ \$0.002 per kwhr.

fits from the low production costs. Thus, the older plants were pushed up into the peak part of the load. It is economical to do this because, as capacity factors decrease, the production cost becomes a smaller percentage of the total unit cost of power, and because of the large economic gains possible by substituting high efficiency plants on the lower portion of the load curve formerly occupied by the older plants of lower efficiency.

In order to make it economical to supersede an old steam plant which carries the peak loads of a system with some other plant or device for performing the same function, it is necessary that the total annual cost of the proposed new plant shall be less than the annual production cost of the old plant without con-

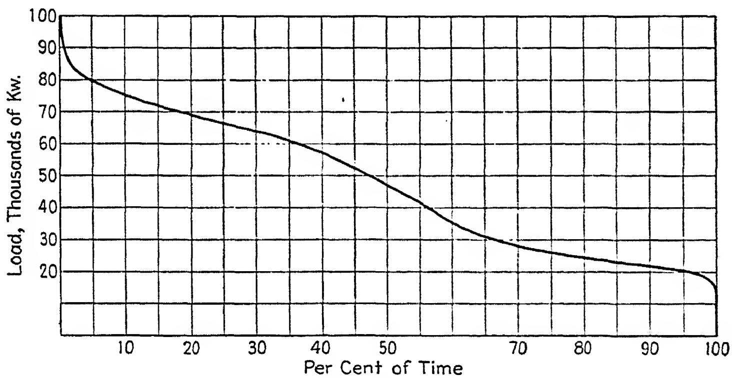


FIG. 43. Load duration curve for the year 1932 for Regional Power Company having an annual load factor of 47 per cent.

sidering any return on the investment in the old plant. Thus, because the old steam plant does not have to show a return on its investment, it is frequently found economically advisable to retain it for peak load and reserve service, even though production cost when operating may be very high for the relatively small number of hours per year during which it is turning out energy.

165. Possibilities for Peak Load Steam Plants. — Many systems now have several highly efficient steam plants. The gains from substituting new plants for the old ones on the high load factor portion of the load curve cannot be as great as they have been in the past. With this situation in mind, engineers have been considering the building of low cost capacity of various kinds to take care only of the peak portion of the load. It has been pointed out previously that increases in economy in a power

station are gained only at the expense of additional capital expenditures.[2] Conversely, if a plant is made less efficient, it should not cost as much as the more efficient plants. This has been the thought behind various proposals to build low cost peak load stations.

Probably the most favorable condition for the building of a plant of this type is a situation where additional capacity is required and where all the existing plants have been built to operate at the lowest cost possible with the existing coal cost. Assume that these plants have been designed to produce at best efficiency a kwhr for 12,000 Btu. The production cost is $3.00 per kw of capacity plus 2 mills per kwhr generated. (See Chapter VI describing this method of dividing costs.) The new capacity to be built will cost $100 per kw, and the annual fixed charges are $13.50 per kw. The increase in capacity desired is 30,000 kw, and the annual load factor of this increased load is the same as that of the curve in Fig. 43, namely, 47 per cent. By adding this load to the load as shown in Fig. 43, the top 30,000 kw will have an annual load factor of 3 per cent. Thus, the new 12,000 Btu plant may operate on any part of the load curve without affecting the total cost of power.

Assume also that it is possible to build a plant of the same capacity of much lower efficiency, say, 20,000 Btu, at less cost. This plant, with the same coal cost, will have an annual production cost of $3.70 per kw of capacity and 3.05 mills per kwhr generated. Thus, the problem becomes one of determining the maximum allowable cost for this low efficiency plant without increasing the total cost of power on the entire load. In tabular form, it may be stated as follows:

Annual operating cost 20,000 Btu plant: $3.70 per kw capacity + $0.0035 per kwhr @ 3 per cent load factor.	= $0.0175 per kwhr
Annual operating cost 12,000 Btu plant: $3.00 per kw capacity + $0.002 per kwhr @ 3 per cent load factor.	= 0.0134 per kwhr
Excess annual production cost of low efficiency plant	= $0.0041 per kwhr

This excess per kilowatt-hour is equal to $1.08 per kw year at 3 per cent load factor, and if capitalized at 13.5 per cent for

[2] See Chapter VI, Section 89.

fixed charges, would represent an investment of $8.00. Therefore, not to increase the total cost of power, the low efficiency plant must have an investment per kilowatt of capacity of $8.00 less than the high efficiency plant. If this latter plant costs $100 per kw, then $92.00 is the maximum allowable cost for the low efficiency plant, and any cost less than this would represent a saving to the system under the assumed conditions. In Chapter VI, it is shown that only 40 per cent of the total cost of a plant is affected by changes in thermal performance, and that to some extent 45 per cent of the cost is influenced by selection of equipment, design, etc.

Although it may be possible to make some saving in first cost in this second item, by proper selection of equipment for short hour operation, such as coal handling, water conduits, pumps, etc., it is evident that the greater burden of the saving will have to be borne by the thermal equipment. In the case illustrated, this would require a reduction in first cost of this equipment of 20 per cent. The example cited is entirely hypothetical, and it will be a very unusual situation, where all plants are of an equal efficiency, which cannot be bettered by a new plant. For this reason, it has not proved feasible to build peak load steam plants.

166. Overload Steam Capacity for Peak Service. — It has been shown that reserve capacity[3] is often provided by installing equipment with overload capacity beyond the most efficient operating range. This same principle can be and is often applied to obtain additional peak capacity. If it is necessary to provide peak capacity to carry short, sharp peaks in addition to the capacity already assigned to the peak part of the load, this method is often favored because it can be obtained at relatively low first cost, and the inefficiencies resulting are of little importance because of the few hours during which it is used. As an alternative to other special provisions for carrying peak loads, it may be economical where the peak capacity carried in this manner does not exceed 10 per cent of the station capacity. For overloads beyond this, the operating difficulties encountered would probably outweigh any advantages of low first cost.

167. Steam Accumulators for Peak Loads. — Steam accumulator plants have also been suggested for carrying peak loads. In Germany, at the Charlottenburg Station in Berlin, one such

[3] See Chapter IV, Section 61.

plant has been built. The load served is of very low annual load factor, about 31 per cent, with a very sharp peak of short duration. The economic possibilities of utilizing steam accumulators for helping to carry the short, sharp peaks on steam plants have been analyzed in an able paper by A. G. Christie, published in the Transactions of the American Society of Mechanical Engineers, Vol. 51, No. 12, page 109. Accumulator experience in this country has been limited to steel mills, and other industries for balancing steam demands with power demands; that is, in periods where power in excess of the exhaust steam is required, the excess steam is stored to be used when the steam demands increase.

Although special situations will develop where the use of steam accumulators may provide an economical means of carrying short time sharp peaks, it is believed that in most cases other means are available for carrying peak loads which will prove more economical, such as old steam plants, steam plants with overload capacity, peak load hydro plants and pumped storage hydro plants.

168. Peak Load Hydro Plants.—A peak load hydro plant is one which is designed and constructed primarily for the purpose of taking care of the peak loads of a power system. For instance, the hydro plant shown as taking care of band *A* in Fig. 42 is purely a peak load plant. A relatively large reservoir is usually an essential of such a plant. Usually but not always the reservoir is large enough to provide for at least some seasonal regulation of the stream.

Installation in relation to average annual stream flow is usually large. Whereas run of river hydro electric plants are usually installed on a plant discharge capacity basis of 1.5 to 4 cfs per square mile, peak load hydro plants provided with seasonal storage may sometimes be installed on a basis of 8 to 15 cfs per square mile. Usually, but not necessarily, such plants are located on the smaller creeks and rivers under topographical and geological conditions such that storage reservoirs may be constructed cheaply with relatively high heads available for the peak load plants without having excessively long penstocks.

Sometimes several such plants are located on a single tributary of a river and the water from the storage reservoirs passes through several of them on its way to the main river (as in Fig. 44), where a number of run of river plants may be located. Ex-

amples of peak load hydro plants are at Tallulah Falls, Ga.; Davis Bridge, Vt.; Soft Maple, N. Y., and Wallenpaupack, Pa.

169. Pumped Storage Plants for Peak Loads. — Pumped storage hydro plants are peak load plants which pump all or a portion of their own water supply. Essentially they consist of a tailwater pond, which may be replaced by a river or a natural lake, and a headwater pond. During times of peak load, water

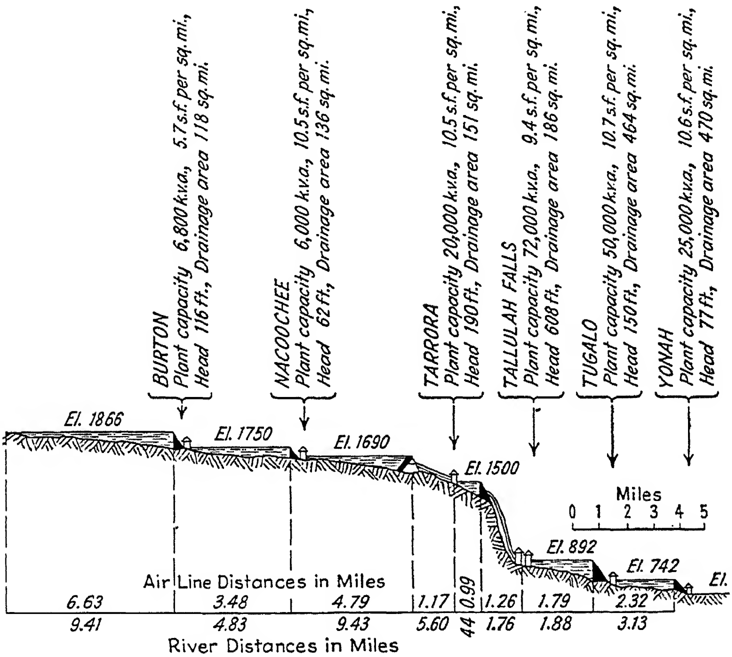


FIG. 44. Peak load hydro plants of Georgia Power Company on Tallulah and Tugalo Rivers. (The two lower plants are on the Tugalo River and the others on its tributary the Tallulah.)

is drawn from the headwater pond through the penstocks to operate hydro electric generating units over the peak of the load curve. During the off peak hours, pumps are operated to shunt the water back from the tailwater pond to the headwater pond. Power for operating the pumps is furnished by off peak steam generated energy, sometimes supplemented by secondary hydro energy. In some cases it is feasible to use the same unit for both pumping water and generating power.

Reservoirs for such developments are usually small, merely

large enough to provide for the operation of the plant over the top of the peak load of the system which it is designed to serve, with some margin to permit of using the plant for short time

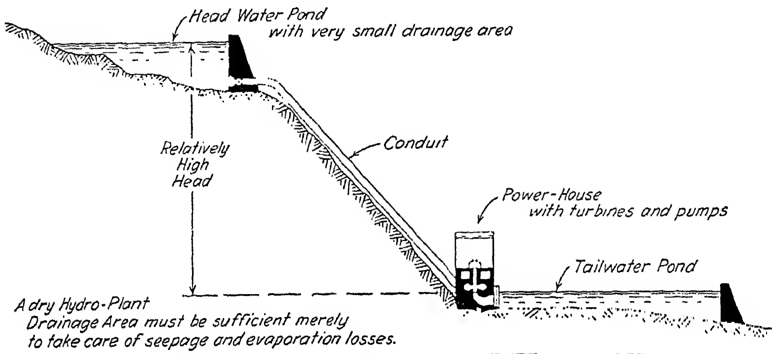


FIG. 45. Pumped storage hydro electric plant installed for peak load purposes only. Headwater and tailwater ponds sufficient for daily or weekly cycle of operations.

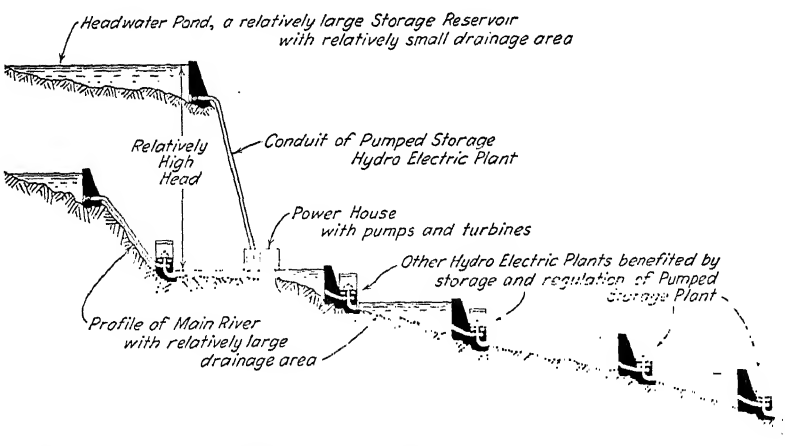


FIG. 46. Pumped storage hydro electric plant intended for regulation and for peak load purposes. Headwater pond is a large storage reservoir, but drainage area may be very small. Tailwater is a relatively large river and is the headwater of a hydro plant having relatively large drainage area.

The pumped storage plant provides peak load service and also seasonal regulation for the other plants.

breakdown reserve service. A reservoir capacity which will permit of full capacity operation of the plant for 4 to 10 hours is usual. Occasionally seasonal storage has been provided for the benefit of other hydro plants on the river into which the

discharge from the plant finally finds its way. The Hengstey plant in the Ruhr, Germany, and the Rocky River plant in Connecticut, are examples of pumped storage hydro electric plants. Pumped storage plants are unique among hydro electric plants in that practically no water supply is required. After the headwater or tailwater pond is once filled, only enough inflow is required to take care of evaporation and seepage losses. Figures 45 and 46 show in a diagrammatic manner two types of pumped storage hydro plants.

170. Special Application of Peak Load Hydro Plants to Systems with Sharp Peaks. — Peak load hydro plants are especially useful in systems which are subject to sharp and unexpected short time peaks, as in some metropolitan systems. In such systems, a dark afternoon may cause coincidence of peak lighting loads, peak manufacturing loads and peak transportation loads. The result on the system is a sharp short time peak.[4] A load curve of this character necessitates a larger percentage of reserve capacity than is required by most power companies. If the system is 100 per cent steam, a large part of the reserve must be kept hot and turning over ready to pick up any unusual load. This in turn means that the company must keep reserve boiler capacity hot ready to furnish steam in case of such an unusual demand. Consequently, to serve and to be ready to serve such unusual peaks by means of steam electric power is very expensive. Peak load hydro plants, on the other hand, are particularly adapted to perform such service and can frequently do it at much less cost.

171. Functions of Peak Load Hydro Plants. — Referring again to Fig. 33, Chapter IX, it will be noted that in the given week the 38,500 kw hydro plant operates as a peak load plant clipping off the peaks of the load curve and thus permitting the steam plants to operate lower down on the load curve at a higher load factor and lower unit production cost. However, this particular hydro plant is a run of river plant with large pondage, and it would operate exactly in the manner shown only at time of coincidence of minimum December river flow and maximum demand week. Most of the time a great deal more water is available (the average annual capacity factor being in the vicinity of 50 per cent), and the plant then operates further down on the load curve. When full plant discharge is available,

[4] See Fig. 16, Chapter IV.

it operates on the base 24 hours a day and the older steam plants take the peaks.

In many systems the use of purely peak load plants, particularly in connection with storage projects, proves economical. Thus in the system represented in Fig. 33, Chapter IX, assume that, as the load increases in future years, storage is provided on the headwaters of the river system to such an extent that during the minimum December flow and maximum demand week represented by Fig. 33, Chapter IX, there is available at the plant, say, 1,200,000 kwhr instead of the 438,000 kwhr which is available without storage. The net effect of the increase in load and this additional energy is to leave at all times the sharp peaks of the load curve projecting above the band which can be served by this plant.

Consequently these peaks might be served by installing at the reservoir a peak load hydro plant. In many cases, the additional cost of such a peak load hydro plant need not exceed $70 per kw of installed capacity.[5] This low additional cost results from the fact that the cost of dams and reservoir is already incurred for storage and the additional cost is for intake, conduits, power house and equipment. In Chapter X, Sections 151, 152 and 153 deal more particularly with such costs of installation. Such installations should seldom be made until practically all the installed capacity can be firm on the load curve.

Even if the entire cost of the reservoir must be borne by the peak load hydro plant, the low capacity factor and consequent high basis of installation relative to average annual stream flow would frequently assure a low capital cost per kilowatt. The truth of this statement will be apparent from an examination of Figs. 38, 40 and 41.

The prime function of such plants is to carry short time and unusual loads and serve as reserve capacity for the system instantly available in case of need; but at times when operating as reserve, such plants may operate further down on the load curve drawing down the reservoir for this purpose. Such peak load hydro plants permit the better steam plants to operate at more efficient capacity factors and obviate the necessity for retaining in service so many antiquated high production cost steam plants and for carrying so many boilers hot and so many steam units in hot reserve as would otherwise be the case.

[5] For justification of the cost of storage, see Chapter IX, Section 141.

172. Peak Load Hydro Plants to Supersede Old Steam Plants. — It is often convenient to consider peak load plants of this character as competing for the service of the short time and unusual peak loads against the older steam plants which produce only a small amount of energy per year at a high cost. The idea is that it may sometimes be economical to supersede such steam plants with peak load hydro plants. However, in order to make such a procedure economical, it is necessary that the total additional annual cost of such a hydro plant including interest on the investment must be less than the annual cost of the steam plant (excluding interest on the investment) which it is proposed to supersede.

In the present illustration, the total annual cost (including interest) on the hydro plant (capital cost \$70 per kw) would probably be about \$7.00 per kw of installed capacity. Assuming that energy production cost at the old steam plant which it is proposed to supersede would be 4.5 mills per kwhr and that peak load hydro plant would produce 1000 kwhr per kw of capacity, the annual capacity cost of the peak load hydro would be \$7 minus (0.0045 $\times$ 1000) equals \$2.50 per kw.

As previously mentioned, it is assumed that peak load installations are not made until such time as they would be firm capacity on the connected load curve. If now the "transmission liability" (Chapter X, Section 150) on the peak load hydro plant is \$3.00 per kw per year, the total annual capacity cost of the peak load hydro on a delivered basis in comparison with the old steam plant would be \$5.50 per kw. An examination of the listed data for typical steam plants in Table 15 shows that of the nine plants listed, three of the older ones have a fixed cost of operating per kilowatt in excess of this amount; and in Table 18, which gives operating costs for seventeen of the older steam plants, all the plants listed show a fixed cost of operating in excess of \$7.00. When it is realized that in addition to this saving there will be further savings due to discontinuing old steam plants arising from the fact that payments to their replacement reserve (for repairs and renewals) will be stopped and also insurance and taxes on the old plant will be saved,[6] it is evident that there are situations where it would probably prove economical to supersede old steam plants with peak load hydro plants capable

[6] There would also be a credit due to scrap value and the sale of the site or utilization for other purposes.

FIG. 47. Rocky River pumped storage hydro electric plant near New Milford, Conn. 24,000 kw at 230 foot head.

of generating at least as much energy as the old steam plants produce.

TABLE 18

PRODUCTION COSTS AT OLD STEAM PLANTS WHICH FOR THE MOST PART ARE UTILIZED TO SUPPLY PEAK LOADS AND TO SERVE AS RESERVE CAPACITY (NO FIXED CHARGES ARE INCLUDED IN FIGURES GIVEN BELOW)

Plant	Approximate Date Built	Approximate Cost of Fuel per Million Btu*	Installed Capacity, kw	Fixed Cost of Operating per kw per Year	Variable Cost of Operating or Increment Cost of Energy, Mills per kwhr
1	1904	$0.1535	75,000	$8.60	3.95
2	1905	0.1785	17,000	13.50	6.70
3	1910	0.1785	30,000	8.14	5.70
4	1910	0.1535	61,000	7.55	2.77
5	1911–1915	0.0954	65,000	11.46	4.10
6	1915	0.1785	40,000	10.05	4.38
7	1914–1917	0.1605	55,000	10.14	4.40
8	1916–1917	0.0954	33,000	11.40	4.01
9	1917–1921	0.1775	160,000	11.80	3.27
10	1917	0.1605	20,000	8.15	4.60
11	1919–1922	0.0930	25,000	8.80	2.30
12	1923	0.1605	40,000	8.60	3.80
13	1922–1925	0.1530	155,000	7.08	2.07
14	1923	0.0954	27,000	11.42	3.46
15	1926	0.1210	35,000	7.32	2.88
16	1926	0.1210	50,000	9.20	2.77
17	1924–1926	0.1095	22,000	8.22	1.60

* Bituminous coal of a good grade would have 26 to 28 million Btu per net ton; anthracite, 21 million Btu per net ton; oil 6,250,000 Btu per barrel.

Examples of peak load plants situated at large storage reservoirs are Harriman (Davis Bridge, Vt.); Bridgewater, N. C., and Rocky River, Conn.

173. Successful Pumped Storage Hydro Plants. — The utilization of pumped storage hydro plants for carrying the peak loads of a system and for decreasing the operating costs of existing steam plants by giving them better load factors to work on is not new. In Europe, at least 40 such plants are in successful operation, the earliest of which were constructed prior to 1900.[7]

[7] See "Pumped Storage Hydro Electric Plants" by W. W. K. Freeman, Assoc. Mem. Am. Soc. C. E., Transactions Am. Soc. C. E., Vol. 94 (1930), page 884.

The Niederwartha plant near Dresden, Germany, has an installed capacity of 84,000 kw with a head of 460 ft and tailwater and headwater ponds each having a capacity of about 70,000,000 cu ft, or only enough to permit operation of the plant at full capacity for about 7½ hours. The plant is used to cut the peak off the load curve which would otherwise have to be carried by the Dresden steam plants, and off peak energy from these steam plants is used for pumping.

The Hengstey plant in the Ruhr, Germany, adjacent to the coal fields, has an installation of 140,000 kw with a head of 520 ft. There is a small pond at the headwater (about 40,000,000 cu ft), and another small pond at the tailwater. During the off peak night hours, the water is pumped from the tailwater pond to the headwater pond, using off peak steam generated energy. During the on peak day hours, the water is shunted back through the hydro electric generating unit to the tailwater pond again.

Another type of pumped storage plant is constructed to have a seasonal regulating effect on other plants located farther down on the watershed. The headwater of such a plant consists of a storage reservoir of considerable size. The Rocky River plant,[8] for instance, which has a capacity of 24,000 kw and a head of 230 ft, could operate six hours each day at plant capacity for six consecutive months without any pumping. The natural inflow into the reservoir may be insignificant, or it may furnish a material part of the water supply required. The tailwater of such a plant is either a relatively large river or the headwater of another hydro electric plant on that river, and the discharge from the pumped storage plant may pass through a number of hydro electric plants. The discharge is a maximum at seasons of the year when the flow in the main river is a minimum. Thus, the plant operates to increase the firm capacity of plants on the main river.[9] In this respect, it operates much the same as any storage reservoir the discharge of which is utilized for producing power. The essential difference is that a part of the stored water must be pumped from the main river during periods of high water.

The economic analysis of a project of this sort is identical with that for any power project with storage, except that the cost of

[8] See Figs. 46, 47.

[9] The Rocky River plant for instance, although its installed capacity is only 24,000 kw, creates a total firm capacity of 45,000 kw.

the necessary pumping must be included as an additional operating cost.

Pumped storage peak load hydro plants have one peculiar advantage over the usual type of peak load hydro plant located on a reservoir outlet. In the latter type, if the reservoir is drawn too low, firm capacity may be sacrificed, whereas with the pumped storage type of plant under such conditions, firm capacity may be maintained by doing additional off peak pumping.

174. Capital Cost of Pumped Storage Hydro Plants. — Although the cost of hydro electric projects is frequently 2 to 2.5 times that of steam plants, a large part of the cost is in dams, lands, reservoirs and riparian rights. The incremental capital cost (i.e., that part of the cost which is roughly proportional to installation) frequently is between \$55 and \$70 per kw.[10]

For pumped storage hydro plants, usually no expensive river work is involved. A site may be chosen almost solely with regard to obtaining a relatively high head, together with a relatively short penstock. Usually no expensive dams are involved, as the reservoir is generally small and the dams low and short. Such projects must, of course, be located relatively close to the load which they are to serve. There are many places where such plants may be built at a total capital cost of \$100 per kw or less. If a large storage reservoir is included for regulating the flow of a river on which other power plants are located, the cost and also the advantages will be greater. At one pumped storage hydro plant, with which the authors were connected, provision was made for greatly increasing the initial installed capacity, and the reservoir capacity was also large to provide seasonal regulation of stream flow for existing and future plants on the river into which it discharged. This resulted in a capital cost of \$132 per kw of initial firm capacity. The return on the investment in this particular project has proved entirely satisfactory and will be even more profitable at such time as additional firm capacity can be added.

175. Pumped Storage Hydro Plants to Replace Old Steam Plants. — In many situations, pumped storage hydro plants may prove economical as competitors for that portion of the annual load curve now served by the older steam plants having a high operating cost and a low annual capacity factor. Many such plants are continued in service as reserve capacity and to take

[10] See Fig. 40, Chapter XI, and Chapter X, Sections 151 to 154 inclusive.

the peak of the annual load. It will not usually be economically advisable to supersede an old steam plant with such a pumped storage plant unless the total annual cost of the latter type of plant including fixed charges is less than operating cost plus taxes, insurance and annual cost of renewals and replacements for the old steam plant. In other words, when a pumped storage hydro plant is proposed to supersede an old steam plant, the pumped storage hydro plant on which all annual costs should be considered must compete with a steam plant which does not have to earn any return on the capital invested in it. From Table 18 it will be noted that there are in this list seven of the older steam plants having a fixed operating cost of more than $10 per kw per year and a marginal energy cost running up to 6.7 mills.

For illustrative purposes, it will be assumed that the fixed operating cost of the old steam plant which it is proposed to supersede is $11 per kw and the marginal cost of energy produced by it is 5 mills. Taxes and insurance on the old steam plant will be assumed at $2.50 per kw and renewals and replacements at $2.00 per kw.[11] Ten per cent on capital cost will be assumed as the total annual cost of the pumped storage hydro plant, exclusive of energy purchased for pumping. The maximum permissible capital cost of the pumped storage plant would then be $\$15.50 \div 0.10 = \$155$ per kw. If the overall efficiency of the pumped storage plant from energy purchased for pumping to energy delivered by the plant were 65 per cent,[12] the maximum permissible price for purchased energy would be $5 \times 0.65 = 3.25$ mills, in order to have the total annual cost of energy from the two plants identical.

In other words, in the above case a pumped storage plant producing the same amount of energy per year as the old steam plant would produce power and energy at a total cost equal to the cost at the old steam plant, excluding return on the investment, if the capital cost of the pumped storage plant was $155 per kw and off peak energy for pumping cost 3.25 mills per kwhr.

In any comparative set-up to determine the economic advisability of superseding an old steam plant with a pumped storage hydro plant, it is necessary to include in the annual cost of the

[11] This is assumed to be the actual average annual cost of renewals and replacements, and not the usual annual payment to renewals and replacements reserve. In other words, it is depreciation minus the obsolescence factor.

[12] This was the overall efficiency at the Rocky River plant.

old steam plant the annual cost of renewals and replacements. Even though the investment in the old steam plant has been entirely written off the books, it will still be necessary if the plant is kept in service to make certain renewals and replacements from year to year.

The annual sum per kilowatt estimated for this purpose should usually be less than the annual payments to the reserve for renewals and replacements which includes an obsolescence factor. The annual sum included should be that sum which by the sinking fund method will take care of keeping the plant as a whole in as good condition as when new.

In a certain large power system subject to occasional sharp peak loads, there is an old steam plant having a capacity of 100,000 kw, which is kept in reserve most of the time, but which is operated to carry short time occasional peak loads. For several years the annual capacity factor has averaged 10 per cent.

The fixed cost of operating at the plant is $9.30 per kw of capacity, and whenever the plant is called on to produce energy, there is an additional cost of 5.3 mills per kwhr.

It is proposed to supersede this old steam plant with a pumped storage hydro electric plant, and a suitable site has been investigated which will have a tailwater and a headwater pond sufficient to permit of full capacity operation over the peak of the load curve. The proposed capacity is 100,000 kw and the estimated total cost is $9,000,000. The overall efficiency of the plant from electrical energy to water and back again to electrical energy has been determined as averaging 65 per cent. Off peak energy for pumping will be obtained from one of the company's modern steam plants at the incremental cost $0.0022 per kwhr.

Annual Cost of the Old Steam Plant Exclusive of Interest on the Investment

Capacity 100,000 kw. Annual capacity factor 10 per cent.

Fixed cost of operating 100,000 kw @ $9.30 per kw per year	$930,000
Variable cost 87,600,000 kwhr @ 5.3 mills	464,000
Renewals and replacements 100,000 kw @ $2.00 per kw	200,000
Taxes and insurance @ $2.50 per kw	250,000
Annual cost of old steam plant excluding return on the investment	$1,844,000

Total Annual Cost of Proposed Pumped Storage Hydro Electric Plant to Replace the Old Steam Plant

Capacity 100,000 kw. Cost $9,000,000. Annual capacity factor 10 per cent

(*a*) Operation and maintenance cost at hydro plant (Fig. 37)	$80,000
(*b*) Depreciation 1 per cent on capital cost.	90,000
(*c*) Taxes and insurance 1 per cent on capital cost	90,000
(*d*) Off peak steam generated energy for pumping 135,000,000 kwhr @ 2.2 mills	297,000
(*e*) Sub-total.	557,000
(*f*) Annual cost of money for project 7 per cent on $9,000,000	560,000
(*g*) Total annual cost of pumped storage hydro plant	$1,117,000
(*h*) Total annual cost of old steam plant excluding return on investment.	1,844,000
(*i*) Annual profit on scheme above annual cost of money	$727,000

Or the net return on the new money to be invested in the pumped storage hydro plant is $\frac{(h) - (e)}{9,000,000} = \frac{1,267,000}{9,000,000} = 14.1$ per cent, which is sufficiently in excess of the average return on public utility property to make the proposed investment in a pumped storage hydro electric project very desirable.

176. Net Return on Investment in Pumped Storage Hydro Plants Used to Supersede Old Steam Plants. — The application of pumped storage hydro electric plants for superseding old steam plants for peak load service is shown in Fig. 48, which gives a series of curves showing the net percentage return on the capital cost of pumped storage hydro electric plants for various capital costs of the hydro plants and various operating costs at old steam plants. It is here assumed that the old steam plants do not produce any return on the money invested in them.

Both the old steam plant and the alternative pumped storage plant are assumed to operate on annual capacity factors of 15 per cent. A proposed pumped storage hydro electric development requires a very thorough economic analysis of all the factors involved in order to determine whether or not it is feasible,

but Fig. 48 is interesting in showing to some extent the limits in the application of such plants for this purpose.

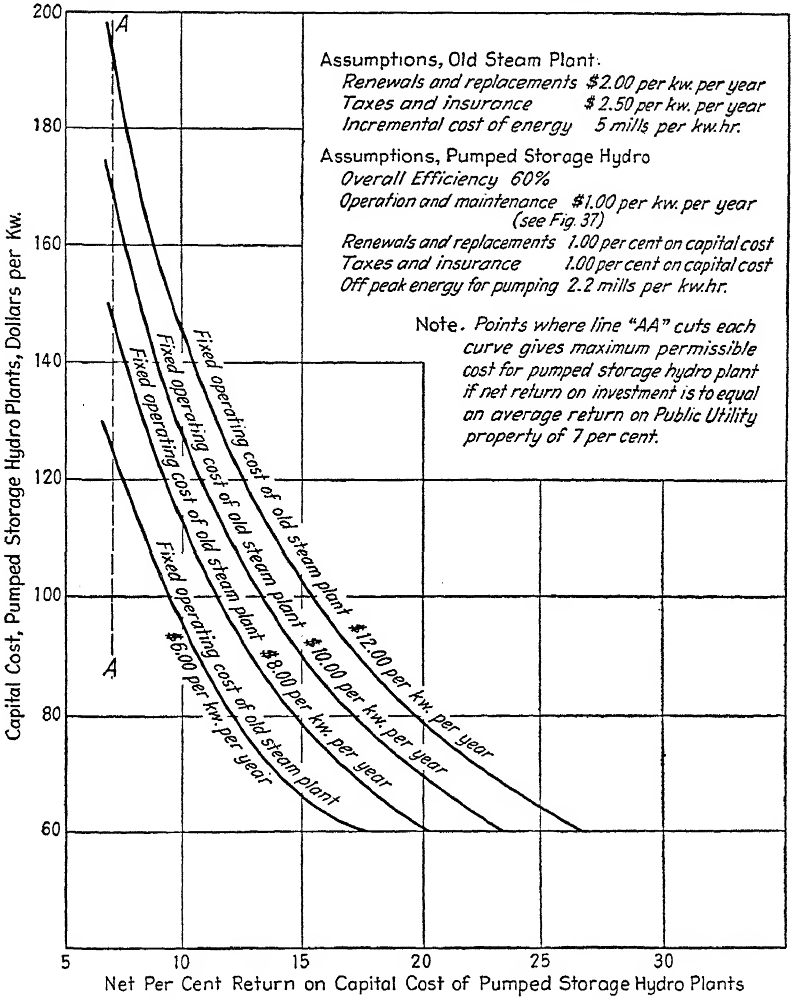


FIG. 48. Per cent return on investment in pumped storage hydro plants used to supersede old steam plant.

177. Pumped Storage Hydro Plant Instead of Adding New Steam Capacity. — If a system already contains highly efficient modern steam plants and/or base load hydro plants, it is worth while when additional capacity is required to consider the advisability of utilizing a pumped storage hydro electric plant as an

alternative to adding an additional steam plant to the system. Such a plant would operate to carry the peak loads, thus improving the load factor on the existing steam plants.

Thus, a certain system, we will assume, is already equipped with efficient modern steam plants of sufficient capacity to carry the load and the antiquated steam capacity is sufficient to supply only the reserve equipment. Although the authors know of no system which entirely meets these requirements, this is the condition which many believe is being approached; at first the assumption will be made because it greatly simplifies the comparison, and later it will be modified to comply with conditions more frequently met with in actual practice.

To take care of the growth in load, it is proposed to add a new 40,000 kw steam plant, but a pumped storage hydro electric plant of the same capacity is being considered as a possible alternative to such a steam plant.

Annual Cost of Alternative Pumped Storage Hydro Electric Plant

Capital cost $90 per kw. Annual capacity factor 10 per cent. Capacity 40,000 kw.

Overall efficiency, 60 per cent

Fixed charges on hydro 9 per cent on $3,600,000 (see Chapter X, Section 148)	$324,000
Operation and maintenance @ $1 per kw (see Fig. 37)	40,000
Off peak energy for pumping 58,400,000 kwhr @ 1.57 mills	92,000
Total annual cost of pumped storage hydro plant	$456,000

Annual Cost of Alternative Steam Plant

14,000 Btu coal cost $3.00 per net ton

Capacity 40,000 kw. Capital cost $100 per kw. Annual capacity factor 10 per cent

Fixed charges on steam plant 13.5 per cent on $4,000,000 (see Chapter VI, Section 100)	$540,000
Fixed cost of operating @ $3.57 per kw per year	143,000
Increment cost of energy 34,900,000 kwhr @ 1.57 mills	55,000
Total annual cost of steam plant	$738,000

Annual advantage in favor of pumped storage hydro electric plant ($738,000 − $456,000) = $282,000.

This advantage would be precisely true only if all the steam plants in the system were equally modern and efficient, producing energy for an incremental cost of 1.57 mills per kwhr, the same as the plant considered. In any practical case, this is quite improbable; to fit a more probable condition, we will now revise our assumption and assume that the next best steam plant in the system has a marginal cost of energy of 2.07 mills. This being the case, the proposed new steam plant having a marginal cost of energy of 1.57 mills would, if constructed, most certainly operate on a much higher annual capacity factor than the 10 per cent previously assumed.

Hence we will assume that the proposed new steam plant would over a term of years operate at an average annual capacity factor of 50 per cent.[13] In that case, the proposed new steam plant would produce $(8760 \times 0.40 \times 40{,}000) = 140{,}000{,}000$ kwhr more energy than the pumped storage hydro plant (10 per cent annual capacity factor) would produce on the load curve. This energy would displace on the load curve the more expensive energy which would otherwise have to be produced by the other steam plant mentioned, and would therefore produce a saving of $(2.07 - 1.57) = 0.5$ mills per kwhr. Consequently, the total saving through the displacement of the more expensive energy would be $140{,}000{,}000 \times \$0.0005 = \$70{,}000$. Hence, the net annual advantage of the pumped storage hydro plant, instead of being \$282,000 per year, would be $(\$282{,}000 - \$70{,}000) = \$212{,}000$ per year.

178. Net Return on Investment in Pumped Storage Hydro Plants as Alternative to New Modern Steam Plant. — In order to show in a very general way the possibilities of installing, in some cases, a pumped storage hydro electric plant as an alternative to a new steam plant, Fig. 49 was prepared showing the net per cent return on the investment for various unit capital costs of pumped storage hydro plants. As in Fig. 48, it is assumed that both the pumped storage hydro plant and the alternative steam plant operate on annual capacity factors of 15 per cent. As has just been pointed out, there is usually an advantage in operating a new steam plant at a much higher annual capacity factor than this in order to displace from the load curve some of the higher cost energy produced by the older steam plants.

[13] This is a considerably higher annual capacity factor than past experience would indicate as probable in the average case. See Chapter XI, Section 158, and Fig. 39.

In some cases, the advantages due to the instant availability of hydro capacity in reducing number of boilers kept hot,

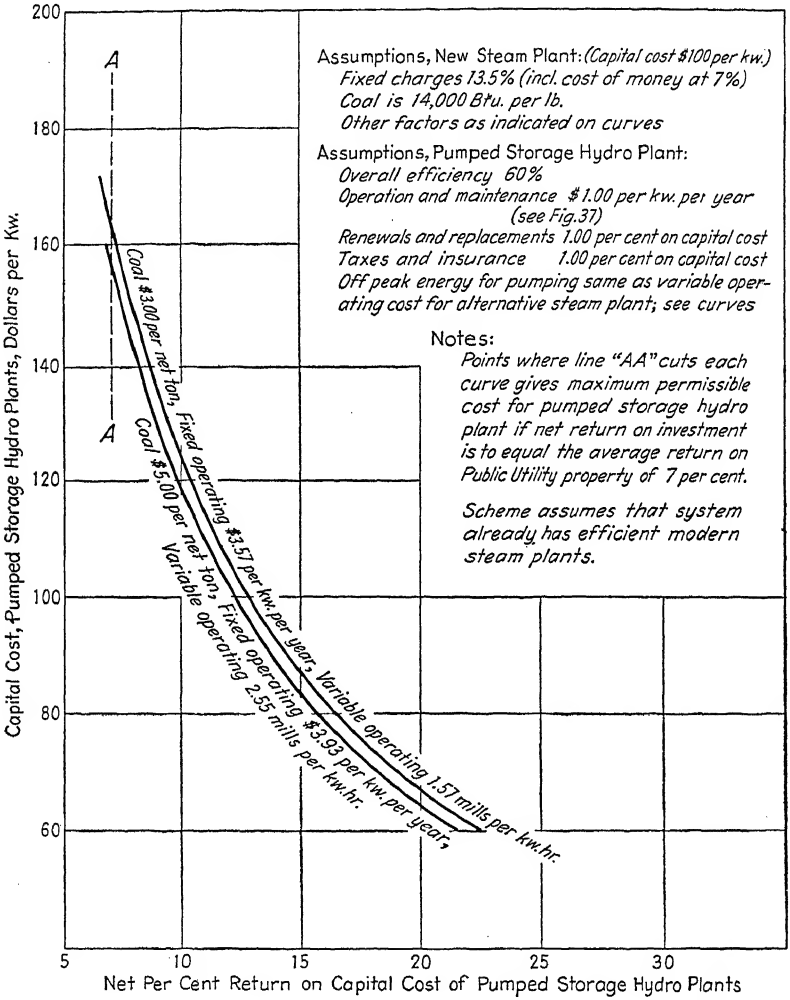


FIG. 49. Per cent return on investment in pumped storage hydro plants as alternative to a new steam plant.

and reducing the amount of hot reserve, may compensate for this liability of the pumped storage hydro. In others, in order to get a true comparison, it will be necessary to make a deduction from any apparent advantage that the pumped stor-

age plant may have, as was done in the specific case previously discussed.

The authors believe, however, that the most promising field for utilizing pumped storage hydro plants lies in superseding the older, less efficient steam plants for peak load service.

CHAPTER XIII

INTERCONNECTION AS AN ELEMENT AFFECTING THE COST OF POWER

179. Development of Interconnection. — Interconnection has undoubtedly contributed more to the reduction of power costs than any other single factor. Any history of the development of the electric power industry that did not tell of the part played by interconnection would be incomplete. In its early years, the electrical industry generally confined its efforts to the more thickly populated metropolitan centers. New York, Philadelphia and Chicago each has the same story to tell about interconnection.

Small plants were built to supply relatively restricted areas. As the business developed and knowledge of generation and transmission of electric energy grew, these plants were brought together, either by agreement or corporate merger, the facilities were interconnected and the small plants were eventually superseded by larger and more efficient ones. This form of interconnection, or as it might better be called "intraconnection," came about normally and excited little interest. It was taken for granted that power plants within a system under a common ownership would be tied together with transmission lines.

Interconnection in the sense in which it is used today means the physical tying together of two or more independently owned or managed electrical systems. Its beginning may have been in 1921, when a survey, under the sponsorship of the U. S. Department of Interior, was made of the power resources and energy requirements, existing and prospective, in the eastern seaboard area extending from Boston to Washington, D. C. The publication of the results of this survey focused public attention on the merits and economies to be gained from the so-called "superpower" systems suggested therein. It is true that for various reasons development has not followed the path outlined in the survey, and it is also true that some form of interconnection had been attempted prior to the report; however, the present era of interconnection can be dated from that report.

180. Where Savings Are Effected by Interconnection. — The coordination of power generating facilities by interconnection has proved universally economical wherever attempted, and has been effective in reducing the cost of power. Economies are created by one or both of the following factors:

1. Avoided investment in production facilities.
2. Reduction in production expenses.

181. Savings Due to Avoided Investment. *Firm Capacity Savings.* — If a power system having a morning peak and a

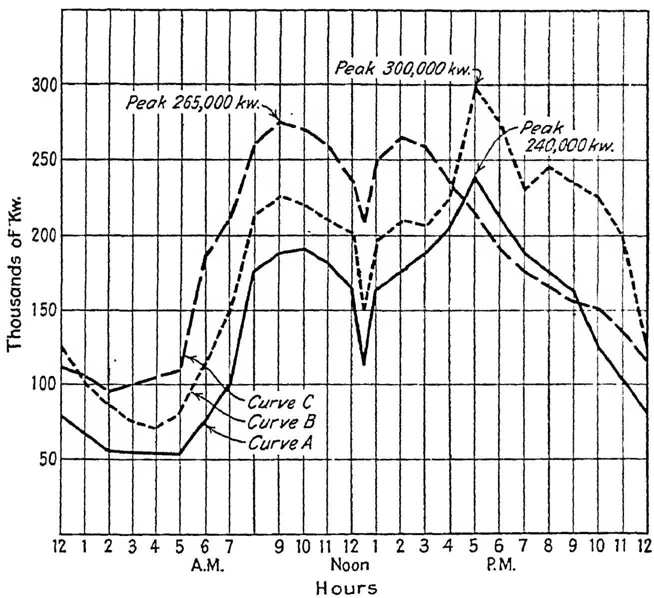


FIG. 50. Curves showing loads of three systems on peak day in peak month.

relatively light evening load, and another system in which the reverse is true, that is, one having a light morning load and an evening peak, can be combined for operation as one, a saving in generating capacity results. This non-coincidence of peaks makes it possible to carry the combined system loads with less generating capacity than would be required if the systems were not combined. The saving in generating capacity is equal to the diversity (see Chapter IV, Section 55) between the two loads, and is the sum of the individual system peak loads, regardless of time of occurrence, minus the peak of the combined systems.

Consider Figs. 50 and 51. In Fig. 50 are shown the load curves for three power systems occurring on the maximum day of the peak month of the year. Curve A shows a maximum demand of 240,000 kw, curve B a demand of 300,000 kw and curve C a demand of 265,000 kw. With these three systems

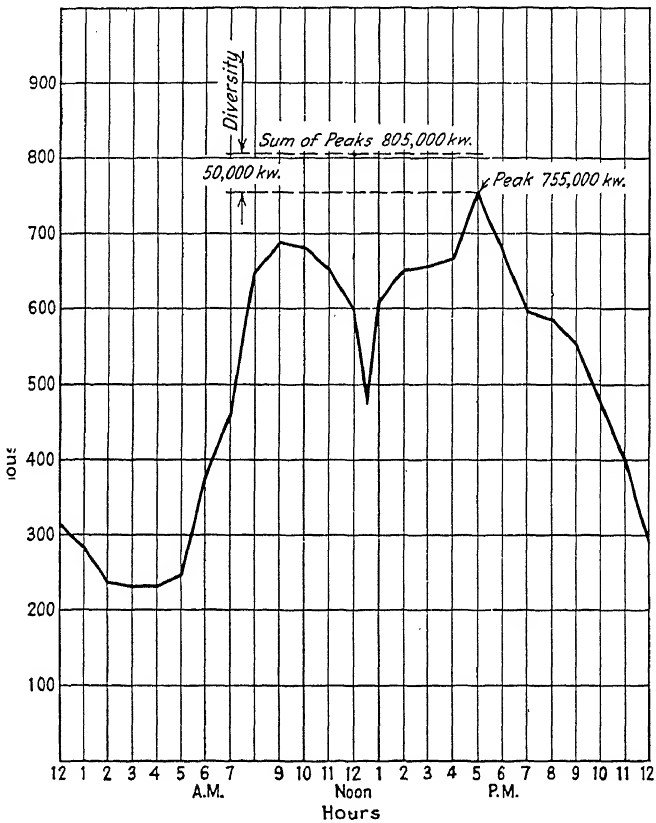


FIG. 51. Combined curve of the loads of three systems showing diversity.

interconnected, a combined curve is produced as in Fig. 51. Separately, the sum of the maximum loads of systems A, B and C results in a total demand of 805,000 kw, and firm capacity, plus reserve, necessary to produce this much power would be required by the three companies. Interconnected, the combined demand is reduced to 755,000 kw, with a resultant capacity saving to be divided among the three systems of 50,000 kw.

If the average cost of this capacity saved is estimated at \$100

per kw, with fixed charges at $13\frac{1}{2}$ per cent, assuming that all the saving is in steam plant capacity, the avoided expenditure is \$5,000,000 and the annual saving in fixed charges is \$675,000. Such savings, to be sure, are not always net, as they must be debited with the fixed charges and operating expenses on the interconnection facilities necessary to produce the saving.

182. Diversity Effecting Capacity Savings. — The example assumed for illustration in Figs. 50 and 51 is a very simple case of diversity occurrence. As shown, it is the daily diversity for the peak month of the year. Diversity occurs in other forms.

There is a monthly diversity which is the diversity created by the non-coincidence of the daily peak loads, and a yearly diversity which is the diversity created by the non-coincidence of the monthly peak loads.

The possible reduction in generating capacity because of diversity is equal to the sum of the daily diversity of the combined peak day, the monthly diversity of the combined peak month and the yearly diversity. Daily and monthly diversities occurring during non-peak periods effect no saving in installed generating capacity. However, they can be used to reduce the amount of capacity required to operate during those periods, including operating reserve, thus effecting savings in production expenses.

183. Reserve Capacity Savings. — Assume that for each system represented by the load curves in Fig. 50 a reserve capacity of 15 per cent of the peak demand was found necessary. The reserve requirement for system *A* would be 36,000 kw; for system *B* 45,000 kw; for system *C* 39,750 kw — a total of 124,750 kw. Ordinarily, reserve requirements are determined by the exercise of judgment rather than by formula, but since it is improbable that a major outage due to accident or some unforeseen cause would occur in all three systems at the same moment, it is reasonable to assume that the reserve requirement with interconnection could be reduced one-third or even more, thus creating another saving in fixed charges on avoided investment.

184. Other Capacity Savings. *By Better Use of Hydro Capacity.* — The combining by interconnection of the loads of two or more systems creates peaks in which, for any given load, the annual load factor is less than the load factor of a similar load in any one of the combined systems. The conversion of

low value hydro energy into capacity of high value on these peaks by the better utilization of the stored hydro energy is outlined in Chapter XII. Thus additional capacity is created and the capacity required from other sources is reduced.

By Planned Construction Programs. — Where loads are growing, no matter how slowly, a system must provide for this growth by extending its generating facilities and bringing into service each year capacity equal to the annual increase in load. This new capacity can be obtained by adding increments of capacity approximately equal to the expected annual load growth, in which case the additions, except in the largest systems, would be relatively small, or by installing large units and waiting for the load increase to build up to that capacity.

With either method, the result is neither entirely satisfactory nor economical. By the first method, the advantage of large units for the reduction of unit capacity costs cannot be obtained. (See Chapter V, Sections 69 to 71 inclusive.) By the second method, although unit capacity costs may be reduced, fixed charges on the unused part of the capacity must be carried for several years.

If two or more companies are interconnected, a " staggered " construction program may be adopted. Under such a program, each company alternates in installing capacity, so that the new power houses can be built with the largest commercial units practicable. The investment on the part of the company building beyond its present needs is carried by the others by purchasing capacity on a short term basis. In this manner, unit capacity costs may be kept to a minimum.

185. Installation of Larger Units Made Possible with Interconnection. — The new load curve created by combining two or more loads when systems are interconnected will be found to have a higher load factor and a larger base load, particularly if some diversity exists between the loads. With the larger base thus created, large generating units may be installed to operate at high load factor with resulting economies not only in first cost but also in operating expense.

In small or moderate size power systems, large units are uneconomical, because, in providing reserve for such units on the theory of reserve for the largest unit in the system, the ratio of reserve to the total becomes too great and the total investment in generating facilities becomes excessive. With the greater com-

bined load and with a reduction in reserve requirements due to interconnection, this objection disappears and larger units may be installed than would be practicable if the systems were separate.

186. Reduction in Operating Expense. — The underlying principle behind all interconnections is the reduction of the total cost of power to the systems so interconnected. Experience has shown that this result can be obtained only by the most complete coordination among the groups involved. There are two schools of thought as to how this coordination may be obtained. One holds that all the benefits of interconnection can be obtained only by operating the combined system under centralized control, just as if the properties were under a common ownership or management. The other believes that such coordination is unnecessary, and that all practical benefits of interconnection may be obtained and still system individuality be maintained.

Except in a few outstanding cases, the maximum economies from interconnection have not yet been attained. Only within the last few years has it been realized that economies in power generation can be made which are of as great or greater importance than the capacity savings. Even the savings due to avoided investment in capacity, although the possibilities in this direction are well understood, have not been completely realized.

The surrender of individual company initiative to a central controlling authority will be necessary in any regional interconnection before all the possible economies can be obtained. There must be coordination not only in loading stations, but also in planning for the extension of existing generating plant to avoid wasteful duplication and over-extension of these facilities.

Neighboring companies first interconnected for the mutual protection of those districts having only one source of power, or for the purchase of firm power to avoid immediate construction of additional generating plant. In New England and in California, interconnections were made to dispose of surplus hydro energy during periods of high stream flow. The transmission lines built for such purposes were usually light and did not permit satisfactory parallel operation of the systems. As these interconnections multiplied, it became evident that, if a better coordination of facilities were possible, savings could be made, not only in capacity, but also in production expense. Upon such considerations was developed the power "pool,"

some examples of which are described in Sections 190 to 194 inclusive.

None of these pools, although effecting considerable savings for the companies participating, have yet reached the stage of complete coordination. The general practice is to have system operators of interconnected companies coordinate the operation of their systems, one with another, to produce unified operation with a resulting lower production cost. Operating problems and practices are reviewed and difficulties adjusted by meetings of these operators. In this way, most of the benefits of a central control are obtained without designating it as such. None, however, have attempted to coordinate both operations and construction programs under the authority of a central control board.

187. Interconnected System Operation. — The operation of an interconnected system differs from system operation under single ownership only by the increase and multiplication of the amount and responsibilities of supervision, and by the necessity of equitably dividing the savings resulting therefrom among the several owners.

Since centralized control of system operation is the common practice under common ownership, in order that interconnection operation may attain results comparable with those possible under common ownership, the methods employed by such centralized control are also desirable and necessary. These methods require the surrender from day to day by the owning company of the right to allocate loads to the plants in its own system, and, in general, they are the methods followed by the principal operating "power pools."

188. Allocation of Loads. — The obligation on the central authority to secure the best operating economies in an interconnected system is:

1. To provide each day operating capacity sufficient to carry the expected loads with adequate reserve capacity available.
2. So to allocate loads to the operating capacity that the energy is generated at the lowest overall total cost.

The first step requires careful planning in advance of the load. Predictions of the monthly average and peak load demands, and weekly forecasts of the load curve, must be made. Maintenance

schedules for the combined systems which may require the outage of any major unit must be set up and coordinated with the weekly and monthly predicted loads in order that sufficient capacity be at all times available. If any of the systems have hydro installations, the energy output from these stations must be predicted.

The second step, that of allocation of loads, is the more important function of the two, and requires a knowledge of the performance characteristics of each plant under all conditions of loading. This is obtained either from test data or from performance records of the plants. These data, properly interpreted, form the basis for the allocation of loads to the various plants.

A number of methods for the interpretation and use of the plant performance data for this purpose have been developed. The economies obtained from the "increment method," though approached by other methods, have so far been the greatest. Therefore, this text will be limited to a discussion of the principal features and operation of this method.

189. Increment Method of Load Allocation. — The criterion for the use of this method is that, aside from local considerations such as voltage regulation, etc., the load shall be increased on that station having the lowest increment cost, corrected for transmission line increment loss.

It is assumed, in the application of this loading method, that all stations and equipment are operating and ready to produce energy. Bringing into service plants from the cold or standby position is a somewhat different problem and involves, in addition to the increment cost, a comparison of the peak prepared for costs on each station (see Chapter VI, Section 103) for the load to be carried.

From the station performance data, there must first be prepared an hourly increment heat rate curve. This curve is developed from the station heat input-output curve, and shows the additional heat input required to add an increment of one kilowatt-hour to the station output. The preparation of this curve is a rather lengthy and technical process. A complete and detailed description is available in N.E.L.A. publication 278-101, "Power Station Betterment Report of the Prime Movers Committee," September, 1928.

Figure 52 shows the increment heat rate curve of two stations

operating as part of an interconnected system. A typical example of the principles underlying the use of the incremental method and the problems encountered in interconnection transactions may be shown in the following example using these curves. Assume that system *A* operating the plant with curve *a* expects 15,000 kw additional load. The plant is already loaded to 50,000 kw. The fuel cost is 17.75 cents per million Btu. From the curve, the average incremental heat required per kilowatt-hour on this plant between 50,000 and 65,000 kw is found to be

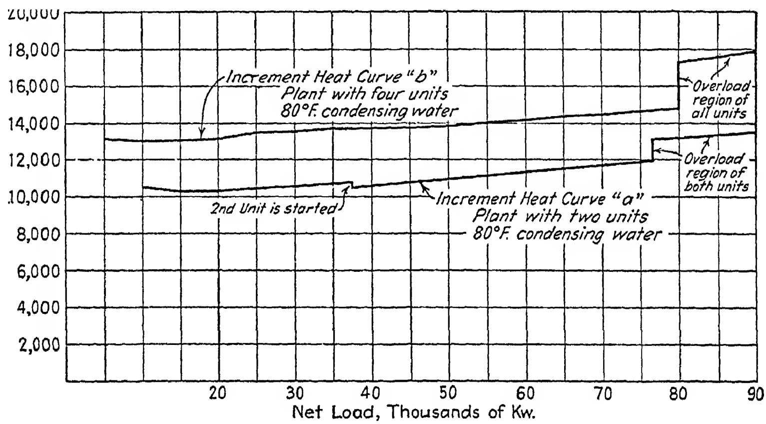


FIG. 52. Typical increment heat rate curves for load allocations.

11,200 Btu. At 17.75 cents per million Btu, this is equal to 1.99 mills per kwhr additional cost.

Plant *B*, with four units in operation, is carrying a load of 60,000 kw. From the incremental heat rate curve of this station, the average incremental heat required to produce a kilowatt-hour between 60,000 kw and 75,000 kw is 14,400 Btu. The fuel cost at this station is 13½ cents per million Btu, so that the increment fuel rate is 1.94 mills per kwhr. If no other considerations were involved, station *B* would be assigned the increase in load.

For the transfer of energy from one system to another, the energy transferred, or its cost, must be corrected for transmission line increment losses. These losses are obtained by dividing the increase or decrease in transmission line losses by the amount of power transferred. Expressed as a percentage, it can be applied directly to the generating cost to obtain the delivered cost. Thus, in the case illustrated, if the increment loss between stations

B and A is 3 per cent for the increment of 15,000 kw, then the delivered cost from B to A is 1.94×1.03, or 1.998 mills per kwhr.

It is also necessary to determine the increment maintenance costs (see Chapter VI, Section 103) on each of these stations and add them to the increment fuel costs. This is done before correction for increment line losses.

In this manner, by starting with the minimum load prescribed by local operating conditions on the steam generating stations, and loading in the order of the increment costs, the load on the station having the lowest increment cost being increased until the next increment on that station will have a cost plus transmission increment losses equal to the next best station, and loading the next station in the same manner, and so on to the next, the lowest production cost of power for the interconnected system is obtained.

190. Power Pools. — In some sections of this country, power companies serving adjoining territories have interconnected their systems to obtain the benefits of interconnection, as far as possible, within the limitations set by state lines, corporate ownership and other artificial barriers. Called "power pools," they represent the pooling of the power generating resources of the subscribing companies in an endeavor to secure the most economical supply of power for each system. Two outstanding ones in the East are the Connecticut Valley Power Exchange and the Pennsylvania-New Jersey Interconnection. Neither of these pools is a corporate entity; the names by which they are called are for convenience only.

191. Connecticut Valley Power Exchange. — This pool began operating in 1925. The area covered by its operations is shown on the map in Fig. 53. The Exchange operates under the supervision of an exchange manager appointed by a committee representing the companies subscribing to the pool. This manager, operating from a central office, is responsible for the allocation of all surplus water power and the selection for use of those steam plants whose operation will result in the greatest combined economies. The exchange manager acts as a middleman or broker among the several power companies. The transactions appear either as a credit or a debit to the accounts of each company. Power is purchased from one company and sold to another company in lieu of the operation by the latter company of a higher cost plant or equipment.

All power is credited at the increment cost to produce to the account of the supplying company, or at the rate that company would receive were it to sell the energy to some other available market. It is charged to the receiving company at its increment rate to produce, or the cost to it in some outside market. Increment costs are determined in the manner described in Chapter VI, Section 103. Increment water power energy is taken at

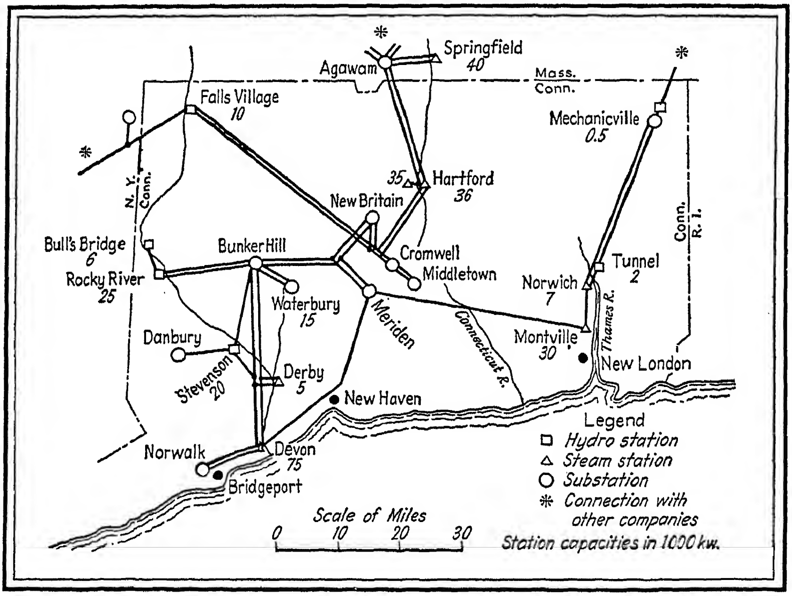


FIG. 53. Territory covered by Connecticut Valley Power Exchange.

zero cost. Corrections are applied to these increment costs for transmission losses.

The difference between the two costs, that of the purchaser and that of the seller, represents the Exchange saving. The net savings, computed monthly, are divided equitably among the companies participating in exchange operations. No contractual relationship exists among these companies. There is only a day to day acceptance of the principles governing the Exchange operations. A résumé of the operation of this pool, showing some of the savings obtained and an outline of the principles under which the pool operates, was published in the August 6, 1927, issue of the Electrical World.

192. Pennsylvania-New Jersey Interconnection. — In a somewhat different manner, but with the same objective, the Philadelphia Electric Company, the Public Service Gas and Electric Company and the Pennsylvania Power and Light Company, operating in New Jersey and the southeastern part of Pennsyl-

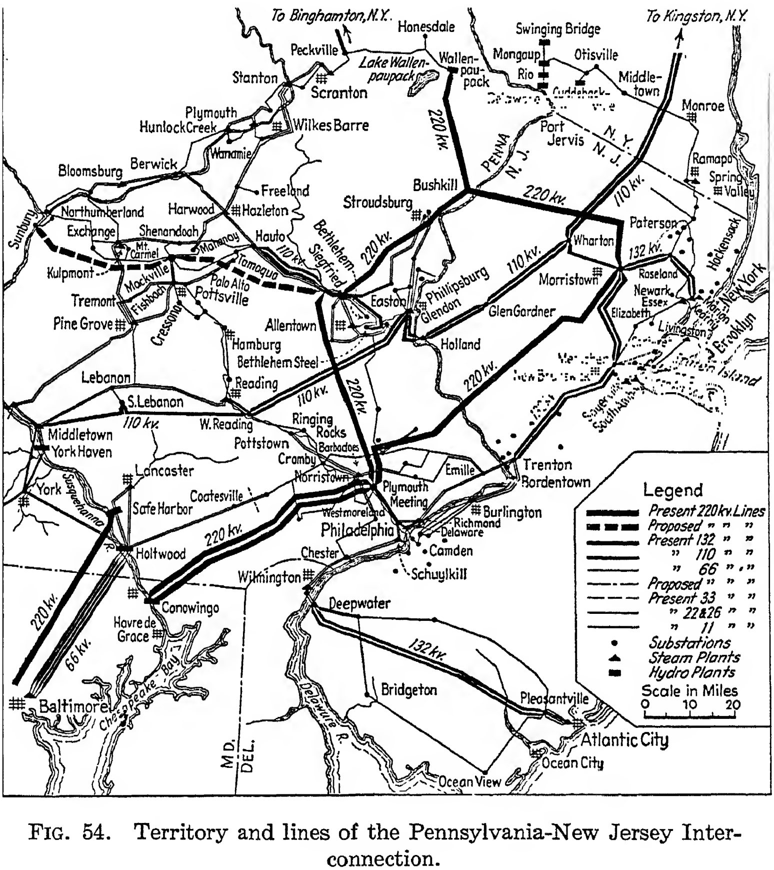


FIG. 54. Territory and lines of the Pennsylvania-New Jersey Interconnection.

vania, have set up the Pennsylvania-New Jersey interconnection. A 220 kv transmission ring was built to connect the systems of these three companies. Contractual relations were established for the construction of this transmission ring, in which provision was made for ownership by each company for that portion built in its chartered territory. (See Fig. 54.)

One feature of this pool is the great diversity among the

companies. The Philadelphia Electric Company and the Public Service Company have loads of similar peak characteristics, with the annual peak occurring in December in the evening, and at approximately the same hour. The Pennsylvania Power and Light Company, supplying a large mining and industrial load, has an annual peak occurring in October in the daytime.

Contractual arrangements provided for the sharing among the companies of the capacity savings created by this diversity. By this arrangement, the Philadelphia Electric Company and the Public Service Electric and Gas Company supply to the Pennsylvania Power and Light Company in October, at the time of peak demand, the portion of the capacity saved by its diversity; and in December, the Pennsylvania Power and Light Company in turn supplies capacity to the other two companies for use on their peaks. Operations are controlled by an interconnection supervisor, acting through the system load supervisors of each company. Plants are loaded in order of their costs, in accordance with the principles of the increment cost method. Hydro power is so allocated to the combined load curve as to permit, as far as possible, total absorption of all the energy available and to obtain the greatest possible capacity for a limited quantity of water. Savings are divided on the so-called " economy flow " basis; the supplying company is paid for energy by the receiving company a price which represents the sum of the increment cost to the supplying company and one-half the difference between that cost and the increment cost of the receiving company.

193. Other Interconnections. — Other forms of interconnection or power pools are found in the Chicago metropolitan area, where the operating companies are affiliated under the same ownership, and in the Pittsburgh, Cleveland, Ohio River Valley and West Virginia areas. In this latter section, ten independent operating companies of western Pennsylvania, eastern Ohio, West Virginia and Maryland operate their systems in parallel. This interconnected pool, for various reasons, depends primarily for its savings on the reduction in spare generating capacity, operating reserve requirements and the more complete absorption of hydro energy. Economical load allocation to steam plants has not been developed to the extent that it has in the two eastern pools.

A rather unusual form of interconnection is that in which two or more companies have joined to build a power plant to supply each of their systems. In such cases the plant bus is the tie between the systems. The Stanton plant near Scranton, Pa., jointly owned and operated by the Scranton Electric Company and the Pennsylvania Power and Light Company, and the Deepwater, N. J., plant, jointly owned by the Philadelphia Electric Company and the Atlantic City Electric Company, are two examples of this practice.

In this manner it is also possible to get the benefits afforded by interconnection. Larger units may be installed, reserve capacity requirements are diminished and unit capacity factor is improved because of the combined load curve.

194. Interconnection with Industrial Plants. — Interconnection on a wide scale of public service company systems with industrial plant systems offers attractive possibilities for the reduction in the total cost of power. A number of such projects have already been developed along this line. (See Chapter XVI, Sections 235, 239 and 240.) There are opportunities for many more, but the differences in economic viewpoint between the two groups seem to prevent this form of interconnection from progressing as rapidly as it should.

CHAPTER XIV

OIL ENGINE PLANTS

195. Use of Oil Engines in the United States. — The history in the United States of the high compression oil engine, commonly called the Diesel engine, in which heavy oil is ignited by the heat of compression, begins in 1898. At that time Adolphus Busch built a 60 hp unit after the designs of Dr. Diesel. From that small beginning, in spite of the many handicaps and technical difficulties which had to be overcome, production of oil engines increased until in 1929 it reached 440,000 hp of Diesel and semi-Diesel engines. The total installed capacity of oil engine plants in the United States has been stated by some authorities to be as high as 4,000,000 hp, but according to one authority[1] the total installed capacity of these prime movers in the United States was approximately 2,930,000 hp on Jan. 1, 1930. The installation for various services may be classified as follows:

Electric light and power, including municipal plants	650,000 hp
Industrial plants	1,200,000 hp
Pipe line pumping plants	350,000 hp
Marine	600,000 hp
Miscellaneous (mines, water works, etc.)	130,000 hp

Although representing only a small fraction of the total power[2] of prime movers installed in this country, the oil engine is of growing importance, especially in the industrial power plant field.

196. Field of the Oil Engine. — The oil engine has found relatively little use in the public utility power plant field as evidenced in the preceding table. Limited in capacity, because of many technical and manufacturing problems not yet solved, it has not been able to meet the demands of the utilities for the large units required by their loads. In Europe, where this type of prime mover has found greatest development and acceptance, the largest unit built at this writing is rated at 22,500 hp.[3] In

[1] M. J. Read, of Diesel Engine Manufacturers Association.

[2] See Chapter I, Section 8.

[3] City of Copenhagen, Denmark.

the United States the largest single unit is rated at approximately 7000 hp.[4] The average size, however, is small.

Some utilities serving sparsely populated areas have found the oil engine useful where only single circuit transmission lines are economically feasible. The demand for continuity of service from such communities is satisfied by installing an oil engine arranged to start up automatically whenever the voltage on the transmission line drops below a predetermined value.

In communities which have a limited load and which are remote from existing transmission facilities, it is frequently more economical to serve the load requirements by means of local Diesel engine power plants than to construct long transmission lines. Some power companies utilize such plants to supply an intermediate stage in the development of a community. A new and thin territory will first be served by an oil engine plant. When the load has developed to a point which makes such a course economical, the community is connected to the transmission system of the company and the oil engine plant may then be moved to a new community whose prospective load does not justify the expense of transmission.

The chief field for usefulness of the oil engine, other than for marine service, however, is in the industrial plant where capacity requirements are usually well within the available engine sizes. In many such situations it has economic advantages superior to either purchased power or steam generated power, especially where little or no steam is required for space or process heating.

The oil engine has also found much favor in the municipal power plant field where communities have found it expedient to discontinue service from the utility and install their own plants. Here, again, size is not of the same importance as it is with the utility.

Oil engine plants may provide an economical installation where a water supply suitable for the feed water and the condensing needs of a steam plant is unavailable. The water requirement of an oil engine plant is about 3 to 5 per cent of that of a steam plant.

197. Efficiency of the Oil Engine. — The Diesel engine is thermally the most efficient of all prime movers. In heat consumption it approaches the efficiency of the combined mercury-steam turbine cycle. For the 22,500 hp unit referred to above, the guaranteed oil consumption at best loading is about 0.395 lb

[4] Vernon, California.

per bhp per hour (or about 7200 Btu per bhp per hour). Some more recent large installations have a guaranteed consumption of 0.37 lb per bhp per hour. For smaller units down to 200 hp capacity an oil consumption at best load of about 0.45 lb per bhp per hour (or about 8100 Btu per bhp per hour) may be expected. This compares with a usual Btu consumption for a condensing steam plant of 1000 hp capacity of 15,000 to 18,000 Btu per bhp per hour.

Probably the most favorable situation for the oil engine is one where the annual capacity factor is very low or very high. Many industrial plants work only eight hours per day. During non-operating hours, a number of costs in steam plants continue, such as banking coal for the boilers and attendance labor. With an oil engine plant, these costs disappear. When an oil engine plant is not operating, the only costs are fixed charges. For this reason, the oil engine lends itself economically to seasonal or short time loads with corresponding low load factors.

On the other hand, where the load and use factors are very high, in other words, if the plants approach full load all day and all night, every day, the high thermal efficiency of the oil engine may make the total power cost lower than that from any other source under the same conditions of operation.

198. Oil Engines for Peak Loads and Standby Service. — Oil engine plants have been used successfully in reducing the cost of supplying peak loads. Chapter XVI tells how industrial plants by the use of oil engines or gasoline engines may limit demands on the public utility and thus reduce the cost of purchased power. Industrial and municipal power plants have often found it economical to add oil engine capacity to existing steam capacity to supply a small increment in peak demand above the steam capacity. In cases where both steam and power are required oil engines have been installed to perfect the heat balance in back pressure steam plants. Attention has been directed to the unbalance between steam and power demands in some industrial plants and the devices employed to obviate this difficulty when the back pressure plant is used as a source of supply. Complete analyses have shown that often the most profitable design may be obtained by the inclusion of an oil engine power unit.

Such a combination often will result in considerably lower investment and, with the better heat balance obtained, decreased

operating expense. A most interesting installation of this type was described in the Nov. 26, 1929, issue of Power. The Hotel New Yorker decided to install a private steam power plant for generating power because of the large space heating and other demands for low pressure steam. When steam requirements are heavy, this steam will generate all the power required. There are times, however, when steam and power demands are out of balance and steam would have to be wasted to atmosphere, or there would be insufficient exhaust steam and live steam would be required.

To prevent this waste, an oil engine of approximately 500 hp was installed to take that portion of the load above that which could be generated by the steam that could be used, or to prevent the waste of steam to atmosphere when power demands are in excess of the steam demands.

This oil engine will also serve as a reserve unit. A résumé of the operating results from this installation also appeared in Power, in May, 1932. Many other instances of the use of the oil engine for such situations may be found in the current technical press.

199. Investment Costs of Oil Engine Plants. — There seems to be a wide variation in investment costs of oil engine plants as reported from various sources collecting these data. The size factor, of course, affects costs of plants, as also do engine speeds, design and construction of plant and other factors relating to the nature and use of the installation. With increased production and sales, oil engine costs are being reduced. The following data from N.E.L.A. Prime Movers Committee report on oil engines for 1931 shows this trend:

COST FOR ONE 250 HP OIL ENGINE

Year	1924	1925	1926	1927	1928	1929	1930	1931
Dollars per hp	68	67	55	51	50	49	44	35

These figures are for the engine without generator and are presented merely to show that there has been a progressive decrease in the unit capital cost of oil engines. The total investment cost of an oil engine electric generating plant is of course very much greater than the above and includes land, buildings, engine, generator, electrical equipment and auxiliary equipment.

As is also true of steam and hydro plants, the capital cost of oil engine power plants varies greatly with the size of the plant, the local conditions and the particular design adopted. Thus for plants recently constructed the total capital cost has varied from about $100 per kw for plants of large capacity to about $160 per kw for plants of about 500 kw capacity. Plants of much smaller capacity are apt to have a much higher capital cost.

Comparison of the unit cost of a 200 hp oil engine outfit which is set in an unused corner of a manufacturing building and in which no building costs are included, with the unit cost of a new 5000 hp municipal lighting plant housed in such a building as municipal architects often design, is not fair, nor with good judgment should it be made. A detailed estimate of installation cost, as complete as possible, should be made in every instance where an oil engine plant enters into competition with other sources of power.

In all studies involving the use of oil engine plants, in addition to the investment required for the plant, there must be considered:

1. *Fixed charges on investment*: including cost of money, depreciation, taxes and insurance.
2. *Operating costs*: including superintendence and labor, fuel oil, lubricating oil, water for cooling, repairs and maintenance, miscellaneous supplies and expense.

Since each of these costs has an important influence on the total cost of power under any given load condition, they must be determined as accurately as possible.

200. Fixed Charges on Oil Engine Plants. — The elements determining the cost of money for steam power plants are stated in Chapter VI, Section 94. The same elements determine the cost of money for oil engine plants. Likewise, taxes and insurance on oil engine plants are determined by the same factors as determine them on steam power plants (Chapter VI, Section 95).

When the construction of a private industrial power plant is being considered, regardless of whether the plant is to be an oil engine plant, steam plant or hydro plant, the cost of money utilized in the set-up should be at least as much as that average rate of return which the factory as a whole makes, or can properly expect to make, on its total capital investment. This is for the reason that, if the proposed capital is not invested in a power

plant, it may be invested in other improvements or extensions to the factory.

Thus, suppose that a factory has $100,000 to invest. If this sum is spent on improvements or extensions to the factory it will be assumed that the estimated net return on the investment will be 10 per cent. If, as an alternative, the factory might spend the $100,000 for a private power plant, clearly it should be able to make a net return of 10 per cent on such investment in order to make the construction of such a plant worth considering.

On the same principle, the cost of money for public utility power plants is frequently taken as 7 per cent, because this is the overall net return on capital which many public utility companies make or may properly expect to make.

It is around the percentage used for depreciation and obsolescence that the greatest discussion has centered. Because of its quite recent introduction in any considerable numbers, reliable records are not available as to the useful life, and replacements have been brought about largely by growth of load and improvements in design or by other factors of obsolescence and not by physical wearing out. For these reasons there have been much controversy and guessing as to the proper rate for the depreciation factor. For the oil engine plant installed by a manufacturer or industry the same principle is applicable as that outlined for other industrial power plants in Chapter XV, Section 212. In most cases of this kind, obsolescence is the determining factor, and the rate should be sufficient to protect the investment against the risks inherent in the enterprise supplied by the oil engine plant. This coupled with the usual desire of management to amortize investment of this kind during years of prosperity usually compels the use of an obsolescence factor in excess of any that can be determined by an engineering analysis.

For utilities, a rate of fixed charges somewhat higher than that for steam plants, although not so high as the industrial plant rate, should apply. It should be remembered that the depreciation and obsolescence rate determined for a steam plant is the composite of the rates for a greater number of units of equipment than are found in an oil engine plant. This reduces the risk of total replacement on the part of the steam plant as compared to the risk of an oil engine plant.

For municipal plants the same basis for the determination of fixed charges should apply as for the public utility industry,

except that there are no direct taxes to consider and the cost of money may be less.

In this book we have used $13\frac{1}{2}$ per cent as suitable fixed charges on public utility steam plants for illustrative purposes. (See Chapter VI, Section 100.) On the same basis the fixed charges on oil engine plants of public utilities might be taken as 16 per cent of capital cost. For the reason stated above this rate might be too low for many industrial plants and too high for many municipal plants. On this basis the fixed charges per kilowatt of capacity will vary from above $20 per kw for very small plants down to about $10 for plants of several thousand kilowatt capacity.

201. Fuel Costs for Oil Engine Plants. — As with the steam plant, fuel is the principal item entering into the operating cost

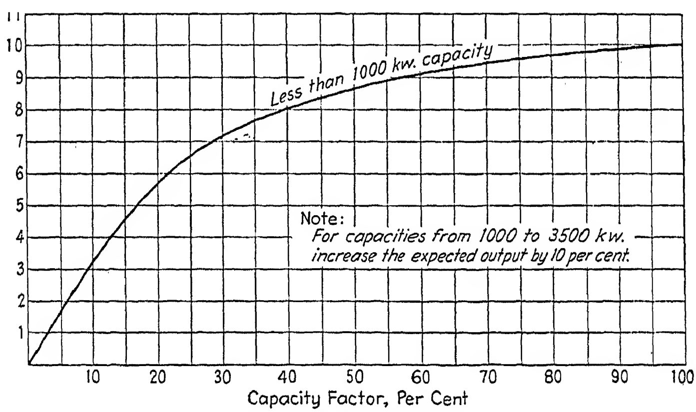


FIG. 55. Expected fuel oil consumption of oil engines.

of power generated by an oil engine. In Fig. 55 is shown the fuel consumption of oil engine plants at various capacity factors. This curve represents a composite plot selected from data on oil engine plants by the A.S.M.E. and the N.E.L.A. 1930 and 1931 reports. Since it represents the average of a great number of plants, actual consumption on individual plants may be either greater or less than that shown. At the present time (1933) the cost of fuel oil is low. In Chapter III the oil situation is discussed in detail and the hazard of installing a plant for the use of fuel oil based on present day prices described. From the consumption curve (Fig. 55) above it will be seen that an increase of one cent per gallon will cause an increase of 1 to 1.5 mills per kilowatt-hour generated.

202. Labor Costs for Oil Engine Plants. — A well trained, well paid force is just as necessary for the successful operation of an oil engine plant as it is for any other type of power plant. Where incompetent labor is employed, high maintenance costs may be expected. The number of men required will depend largely on the plant layout and number and size of units. In small, single or two unit plants, one operator per shift is required. For larger plants, with three or four units of 1000 hp or more, two men will be required, also a superintendent or chief engineer. Labor costs per unit of capacity or per kilowatt-hour generated may be expected to vary widely, depending on the size, type of installation and nature of operation, whether continuous, part time or seasonal.

203. Cost of Maintenance for Oil Engine Plants. — It is frequently the practice to state maintenance cost as a percentage of the total investment and include it in the fixed charges. There seems to be no justification for this practice, and, carelessly used, it may give very erroneous results. A manufacturer of high grade equipment naturally needs to charge more than one whose equipment is not so well constructed. The high grade equipment should cost less to maintain than the other, yet an average percentage figure applied to each penalizes the highest cost equipment. It is evident, also, that the total annual maintenance cost for a unit operating continuously will be considerably in excess of the cost if the same unit were operating on a single daily shift or seasonal basis. For these reasons, the larger part of the maintenance cost will be proportional to the output in kilowatt-hours, with a smaller portion fixed by the number and size of units and nature of the installation.

The fear of excessive maintenance costs is partly responsible for considerable of the existing prejudice, among prospective users, against oil engines. Engines built to sell rather than to operate, over-rating of capacity by the manufacturer and consequent overloading in operation, faulty design and other equally bad practices have contributed largely to this fear. These evils have been recognized and are being corrected by the industry, and it is reasonable to assume that the large maintenance costs incurred in the past will not be duplicated by units now going into service.

204. Cost of Lubricating Oil and Water for Oil Engine Plants. — In any estimate of costs for oil engine power the cost of lubricating oil and of cooling water should not be neglected. About one gallon of lubricating oil for each 800 to 2000 kwhr

generated is required. The cost of water is also an appreciable item of operating expense. Oil engine plants are often installed instead of steam plants because of water scarcity, and where water is scarce it is likely to be expensive, especially if it must be treated to remove impurities. Type of engine, and inlet and outlet water temperatures, will determine the quantity required.

Other costs include those ordinarily classified under miscellaneous expense, such as waste, rags, etc.

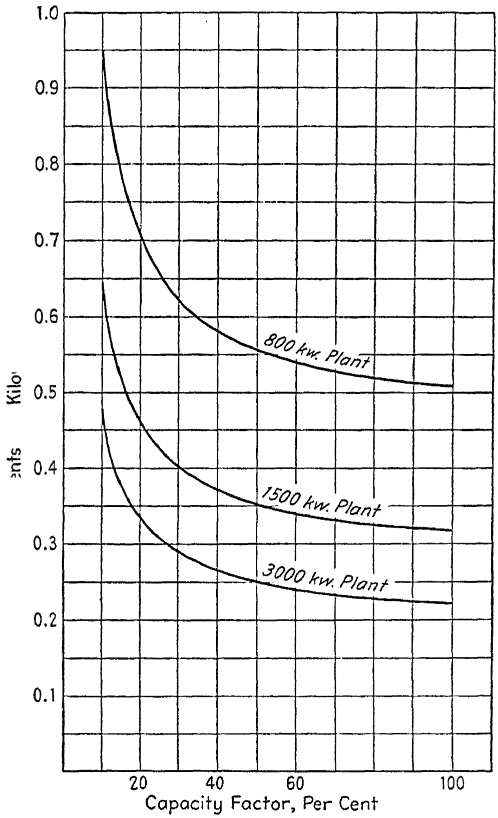


FIG. 56. Operating cost less fuel of three oil engine plants with capacity divided equally among three units.

205. Total Operating Costs of Oil Engine Plants. — Although average figures are of questionable value in any engineering analysis made to compare the cost of oil engine operation with the cost of power from other sources, there are given in Fig. 56,

TABLE 19

Oil Engine Power Costs at Eighteen Plants

Operating costs only. To obtain total cost of power at the plant, fixed charges must be added to total costs here given

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
					Total Cost			Fuel Cost						
No. of Units	Plant Cap. kw	Capacity Factor while in Operation	Net kwhr ×1000	Gross kwhr ×1000	Mills per net kwhr	Mills per gross kwhr	$ per kw-yr	Mills per net kwhr	Mills per gross kwhr	$ per kw-yr	Cost less fuel, $ per kw-yr	Gross kwhr per gallon	Year In-stalled	Report Number
1	275	84.9	365.0	375.1	7.43	7.23	53.70	2.81	2.73	20.28	33.42	11.63	1927	99
1	160	41.5	151.9	157.8	10.79	10.40	37.90	6.23	6.00	21.80	16.10	9.98	1928	169
1	72	13.7	15.89	16.69	174.31	166.00	199.50	12.65	12.03	14.42	185.08	5.80	1927	646
2	1200	48.1	885.4	893.7	12.96	12.83	54.00	6.33	6.27	26.40	27.60	8.83	1-1927 1-1929	109
2	640	45.9	1,123.3	1,268.4	11.90	10.55	42.40	4.69	4.16	16.72	25.68	8.42	2-1927	69
2	500	82.9	1,098.9	1,099.5	8.42	8.41	61.10	4.73	4.72	34.25	26.85	10.50	2-1925	67
2	480	37.0	673.3	733.3	10.91	10.02	32.50	5.02	4.61	14.92	17.58	8.41	2-1930	527
2	440	52.3	1,539.9	1,603.9	12.43	11.93	54.70	5.31	5.10	23.33	31.37	12.55	2-1928	61
2	295	33.2	432.9	489.4	18.54	16.40	47.80	5.45	4.82	14.00	33.80	10.04	1-1919 1-1924	335
3	740	68.1	1,165.3	1,235.5	12.33	11.63	69.50	5.19	4.89	29.30	40.20	9.06	2-1925 1-1927	112
3	480	40.6	403.0	421.0	20.81	19.92	70.80	7.58	7.26	25.80	45.00	7.57	2-1925 1-1929	501
3	3400	65.0	10,027.7	10,454.1	4.08	3.92	22.30	2.25	2.16	12.28	10.02	9.66	2-1928 1-1930	92
4	3400	64.0	8,016.0	8,473.3	4.39	4.16	23.30	1.34	1.27	7.10	16.20	10.26	1-1923 1-1924 2-1928	73
4	3110	75.2	7,257.7	7,391.5	10.29	10.10	66.60	5.30	5.21	34.35	32.25	10.97	3-1928 1-1930	52
4	2524	54.1	4,484.7	4,760.8	8.60	8.10	38.40	4.59	4.32	20.50	17.90	10.89	1-1924 1-1926 1-1929 1-1930	130
5	3675	53.1	8,167.0	8,696.3	5.83	5.48	25.47	3.95	3.71	17.24	8.23	11.03	3-1927 1-1928 1-1930	91
5	2900	69.5	6,908.5	7,492.3	8.20	7.56	46.00	5.18	4.77	29.02	16.98	11.07	3-1923 2-1926	45
7	2800	99.9	22,910.0	24,221.0	5.86	5.54	48.40	2.16	2.04	17.82	30.58	12.39	1925 to 1926	54

Note: Data are from A.S.M.E. Report on Oil Engine Power Costs for 1930.

as a matter of general interest, curves showing costs other than fuel developed from data published by the A.S.M.E. and the N.E.L.A. in their annual oil engine reports for 1930 and 1931. These cost curves represent the average of a number of plants of approximately the same size and type of operation. Table 19 summarizes the actual operating results from a number of plants. The cost figures given are exclusive of fixed charges.

For comparative purposes it is better to use a method of analysis such as that outlined for steam plants in Chapter VI, by dividing the total costs into fixed and variable components. Costs of oil engine plants will respond more readily to the Hopkinson theory[5] of analysis than those of steam plants because of the absence of many cost creating elements, such as pumps, condensers, boilers, which need to be considered in the steam plant analysis.

206. Competition of Oil Engine with Central Station Power. — The development of the high compression oil engine began shortly after the introduction of the steam turbine but its progress has lagged far behind. In the past few years many improvements have been brought forward to lower costs and to increase operating efficiency. Central stations, in the sale of industrial power, as long as the present low level for material and oil costs prevails, will find the competition with them very keen. Its compactness and the ease with which it can be fitted to load conditions are both very desirable features, and with proper analysis of all cost factors, there are many situations where its use can be economically justified.

207. Analysis for a Proposed Municipal Diesel Engine Power Plant Installation. — To illustrate the utilization of the economic principles herein discussed a more or less typical case will be assumed and analyzed. In order to make the illustration quite simple it will be assumed that the City of Arnold, a town of about 5000 people, is already in the power business. The municipality buys its electric power from the regional power company at wholesale but owns its own distribution system and street lighting, and retails the current to the ultimate consumer.

Cost of Purchased Power. — At the present time the average rate which the City of Arnold is paying is 1.645 cents per kwhr, but the rate is actually a two part rate. The peak load for the last calendar year was 1000 kw, and the annual load factor was 38 per cent.

[5] See Chapter XVI, Sections 227 and 228.

The power bill for the year was:

1000 kw @ $18 per kw	=	$18,000
3,300,000 kwhr @ $0.011 per kwhr	=	36,300
Total annual cost of purchased power	=	$54,300

or an average cost of 1.645 cents per kwhr.

The city fathers of Arnold considered this power bill excessive, and, when the power company refused to reduce rates, they appealed to the state public service commission. The commission conducted an extensive (and expensive) investigation but found that the power company was making only a fair return on the fair value of its property and that this particular rate was not unfair.

Diesel Engine Plant Considered by City. — The city is accordingly considering the advisability of terminating the contract with the power company and installing its own Diesel engine power plant. In doing this, however, it realizes that it must continue to give its consumers as reliable service as they have been accustomed to, and accordingly, in order to take care of the load of 1000 kw, a Diesel engine plant of a total net capacity of 1500 kw may be installed in three units of equal size, so that if one should go out at time of peak load the other two could carry the load. Provision would also be made for the installation of a fourth unit when required by growth in load.

The engineer engaged by the city estimates the total capital cost of such a plant, including land, building, Diesel engines, generators, electrical equipment and auxiliary equipment, at $190,000 ($126.50 per kw).

Fixed Charges on Proposed City Plant. — If such a plant as is here proposed were to be built by a public utility the fixed charges should probably not be less than 15 or 16 per cent, including the cost of money at 7 per cent, taxes and insurance at 2 per cent and depreciation and obsolescence at 6 to 7 per cent. In the case of the municipality there are no taxes to be paid, and the cost of money will be assumed at 6 per cent. Accordingly the total fixed charges will be assumed as 12 per cent.

As the power company has no property within the city limits there is no tax revenue from the power company. In cases where the municipalities derive tax revenue from the power company, it is necessary to charge the average annual taxes received into the total annual cost of the proposed municipal plant in order to get a true picture of resulting savings.

Operating Costs of Proposed City Plant. — It is assumed that the plant will use on the average 1 gallon of fuel oil per 11.2 kwhr and that the average cost of oil is $3\frac{1}{2}$ cents per gallon; lubricating oil has been taken to cost 50 cents per gallon, and it has been estimated that 1 gallon per 1600 kwhr will, on the average, be used. The total of operating cost, excluding fuel, amounts to 3.34 mills per net kwhr, which by comparison with the results at plants of similar size and operating on similar load factors[6] appears to be rather low. In general it is believed that operating costs indicated in the set-up are somewhat optimistic, but are consistent with results obtained in well designed, properly operated modern plants of similar size.

TOTAL ANNUAL COST OF PROPOSED DIESEL ENGINE POWER PLANT

Net capacity 1500 kw (3 units, 750 Bhp each).
Peak load 1000 kw; annual load factor 38 per cent; net annual output 3,300,000 kwhr.

		Per kwhr, Mills
1. *Fixed charges*		
12 per cent on $190,000	$22,800	6.19
2. *Operating cost*		
Fuel oil, 295,000 gallons @ $0.035 (11.2 kwhr net per gallon)	10,320	3.13
3. Lubricating oil, 2060 gallons @ $0.50 (1600 kwhr net per gallon)	1,030	0.31
4. Superintendence	2,400	0.73
5. Operators (4) @ $1000	4,000	1.21
6. Miscellaneous labor (1)	840	0.25
7. Maintenance including ordinary repairs	1,600	0.48
8. Miscellaneous supplies and expense	1,200	0.36
Total annual cost	$44,190	13.38

Or an average cost of approximately 1.34 cents per kwhr for 3,300,000 kwhr (net) on a 38 per cent annual load factor.

Saving to City from Owning Its Own Plant. — As the cost of purchased power was $54,300 a year the indicated annual saving that the city would get in the first year of operation by building its own plant is $54,300 − $44,190 = $10,110. On the face of this comparison then the city would be justified in going ahead with the construction of the plant. However, before going ahead the city fathers should consider several factors, any one of which may greatly modify the results attained in future years.

[6] See Table 19 and Fig. 56.

Effect of Increase in Cost of Oil. — Fuel oil is one of the less stable fuels in the matter of price.[7] Compared to the past the present price of fuel oil is low, and accordingly the results of an increase in the cost of oil should be considered. In the illustrative example given, a rise of 2 cents a gallon would reduce the indicated saving to about $4200 a year.

Effect of a Decrease in Rates by the Power Company. — The power company may in the near future reduce its rates, because, regardless of whether or not it is making a fair return, the power business is, after all, a competitive business. We will assume that within a year or two the rates are reduced so that the average rate to the City of Arnold becomes 1 cent per kwhr (an entirely possible contingency). In that event the City of Arnold would be losing approximately $11,000 per year by owning its own plant, assuming that other conditions remained the same. This is on the basis of present load; with an increase in load the loss would be greater.

Effect of an Increase in Load. — In the set-up as made the proposed Diesel engine plant was just large enough to carry the load successfully with the necessary reserve capacity. Any increase in load would require the installation of an additional unit. Thus if the load increases 10 per cent next year the output will increase 10 per cent but fixed charges would increase perhaps 25 per cent. A larger increase of load would, of course, be advantageous, unless public utility rates were materially reduced.

Advisability of City Constructing Plant. — The consideration of factors such as those just discussed indicates that obsolescence in a plant may take place owing to conditions unrelated to the physical plant or to the progress of the art. To guard against such a contingency, it is good practice to require that the net profit remaining after operating expenses, interest on money, depreciation, taxes and insurance are taken care of should be sufficient to justify assuming the risks involved.

In the illustrative case here considered the indicated annual saving of $10,110 would be sufficient to justify the city fathers in going ahead with construction if there are sound reasons for believing that rates for purchased power will not go down and that the price of oil will not rise materially during the years of the near future.

[7] See Chapter III, Section 38.

CHAPTER XV

INDUSTRIAL POWER PLANTS

208. Similarity of the Industrial Power Plant to the Public Utility Plant. — The industrial power plant, in design and construction, regardless of the method used for producing power — steam, oil, engine or water — is governed by the same economic factors that govern the larger central station. Fuel and equipment must be selected in the same manner. Costs respond to size and capacity factor just as costs for central stations do. Each method of producing power is in competition with the other, with an added competition in the form of purchased central station power. Accordingly the present chapter will be confined largely to those factors which make the economics of industrial power differ from the economics of central station power.

209. Economic Conception Different. — The economic conceptions, however, leading to construction of the two types of plant are widely different. The central station supplies the aggregate of a number of loads. Its sole purpose is the production of power to serve these loads. The diversity among these loads maintains a stability in the shape of the load curve over long periods of time. It is relatively simple, therefore, to fit a central station to its load curve.

On the other hand, the industrial plant is subject to no such fixity of load curve. Changes in product or process, in the rate of business activity, either of the whole plant or in the individual departments, all tend to impose varying conditions of load on the private plant not found in the central station system. Even in the same kind of industry, load requirements are usually so unlike that the power plants in their economic conception have little resemblance to one another. For these and many other reasons, the private plant must, from an economic standpoint, be subject to highly individual treatment. It cannot be considered as an economic entity, but only as a unit of the economic whole in which it is simply a part.

210. Reserve Capacity. — This situation is well illustrated in the matter of providing reserve capacity. Some processes are

continuous, and any interruption in the flow of power or steam may cause a great loss in semi-finished product. In some textile processes, for instance, a slight change in electrical frequency causes considerable loss. For such conditions, excess capacity or reserve beyond the normal conception of reserve requirements is installed, and it is profitable to do so because of the possible loss if the power supply is not continuous. Conversely, other industries have a product which can be produced at a uniform rate without seasonal fluctuations and which can be stored. An example of this is coal mining. In case of an interruption of power supply to a mine, production can be stopped without great loss until service is restored. Under such conditions, reserve is seldom provided, except for essential services such as hoisting and ventilation. Therefore, the reserve problem for an industrial power plant must be approached with an entirely different viewpoint from that from which reserve for central stations is considered.

211. Industrial Generation of Power.—Whether an industrial should manufacture its own power or purchase from the central station is a many sided problem in which the economic factor is too often disregarded. Many industrialists prefer to keep out of the power business and devote their time and capital solely to the manufacture of their product, and, therefore, purchase power. Others, through a desire for self-containment, build their own plants. In either case, the resulting situation is sometimes unsound and economically wasteful.

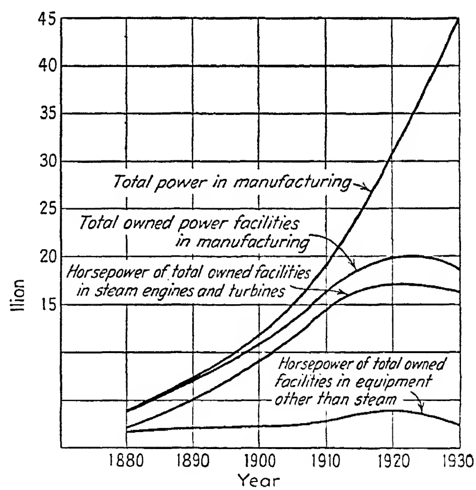


FIG. 57. Capacity of power facilities in industry of United States.

Power should be generated by a private plant only when it can do so at a total cost less than that for which it can be obtained from an outside source.

Figure 57 illustrates the relative growth of industrial power and

industrial plants. The failure of industrial plant development to follow in the later years the growth of industrial power has been brought about by a better understanding of the economic problems involved, and by a lowering of central station rates for power to a more widely competitive basis and a widespread extension of their facilities to serve.

Where an average industrial company develops power, using the same methods and processes as the central station, and setting for itself the same service standard required of the central station, it is evident that in the majority of situations encountered the power so developed will be more costly than that produced by the central station. Size is one important factor. Small scale operations seldom produce at as low costs as those conducted on a large scale. This is particularly true of power production, considering both investment and operating cost, and has been demonstrated many times in preceding chapters in discussing the relationship of size to cost.

The central station concentrates solely on the production of power, whereas the industrial concern concentrates on a finished product in which the production of power takes only a part. The yardsticks by which results are measured are different. Central stations measure costs per unit of power; the industrial plant, per unit of finished product. There are many intervening processes between power and finished product. Because of this, and because industrial management can often obtain greater returns from investment by improving some of the intervening processes than could be obtained from the same investment in power equipment, the average industrial power plant often does not reflect the best possible solution to the power problem of that industry. This holds particularly for the average small plant. In those industries where power is a very large part of the cost of the finished product, such as the paper and chemical industries, or where production is concentrated in large units as in the automobile and steel industries, and the power load resulting is comparable in size to many central station loads, power development is on a scale of overall efficiency equal to the best found in central station practice.

212. Fixed Charges on Industrial Plants. — Industrial management must require an investment in power plant to carry a greater burden of fixed charges than the central station management. The risk in the enterprise supplied with power is the risk

to be considered on power plant investment. The great diversity of load supplied and the ever increasing use of electricity in the home, together with the fact that it is a regulated monopoly, has eliminated much of the risk from central station enterprises. An industrial manager, faced with the possibility of changing markets or processes which may almost over night render an investment in power equipment obsolete, must add, in determining fixed charges, an amount above the annual cost of money which will protect the investment in power equipment in the event of such changes.

213. Advantages of Private Plants. — The preceding statements apply only when the economic situation of the small plant as regards location, fuel supply and type of plant are the same as that of the public utility. However, private plants frequently have a decided advantage over the central station. In many industries, wastes produced by the process often have considerable fuel value if used at the place of production. In outside markets, however, they have little value as fuels because the cost of transportation per unit of heat is high, and because the production is limited in quantity. The sludges and cokes of oil refineries, blast furnace gases from the steel mills and the wood wastes of the wood working industries are examples. Where such conditions exist, the fuel cost in power production becomes a negligible item, the use of the fuel sometimes representing a saving because of the cost of disposal if the wastes were not used. Under such circumstances, the central station plant is at a disadvantage and costs are not comparable.

214. Industrial Steam Plants. — There are two kinds of stationary steam plants: those used for the production of power for public use, the central stations; and those used for the supply of power for private use, the industrial power plants. In this latter class are included not only the plants used for power supply to large industries, such as steel mills, paper and textile plants, but also the plants installed to supply to laundries, office buildings, stores and the like. Many industrial steam power plants compare favorably in size and design with central stations. Steel companies and coal companies are large users of power and in many situations have built large and efficient plants to supply their needs. The largest steam turbine built to operate at 1200 lb pressure is installed in one of the power plants of the Ford Automobile Company. The highest operating steam pressure

for power generation is found in an industrial plant. However, the average industrial plant is quite small, seldom exceeding 5000 kw in capacity.

215. Design and Construction. — In design and construction, there is a great resemblance between the two types of plant. Because their interest is centered on one thing only, the production of power, their ultimate product, central stations have pioneered in the development of boilers, turbines, fuel burning apparatus and other power plant equipment. The private plant, in most cases, has found it desirable and practicable to follow in the path of these developments, with the result that the equipment and practices for the two types of plants are very similar. By the development of equipment for generating high pressure steam, pioneered largely by the utilities, private plants have been given an instrument of tremendous value for the development of their own plants, particularly in those where process steam is produced.

216. Back Pressure Steam Plants. — In many industries there is a need for heat, both for process and for space heating. The power supply problem and the heat supply problem then become one, and in the consideration of an industrial plant must be linked together.

In order to supply the process and space heating need, a boiler plant is required. If, before the steam is used, it is allowed to expand in an engine or turbine, power will be generated. The quantity of the power so generated will depend on the quantity of steam used, on the initial and final steam conditions and on the machine efficiencies.

These so-called "back pressure" steam plants are much more efficient in producing power than the typical condensing plant. In the latter type of plant, from two-thirds to three-quarters of the initial total heat of the steam remains in the steam exhausted to the condenser, and is absorbed by the circulating water. The very best of such plants use from 11,000 to 12,000 Btu from the fuel to produce 1 kwhr. On the other hand, in the back pressure plant, the heat of the exhaust steam is not chargeable to the production of power, but is charged to the processes that use it. Only the heat of the energy itself, viz., 3412 Btu per kwhr, and the heat consumed by radiation and friction losses, are chargeable to the energy produced. Thus the heat cost of a kilowatt-hour in a back pressure plant is from 4500 to 5000 Btu

depending chiefly on the efficiency of the fuel conversion in the boiler plant.

It has been pointed out previously that, in a condensing plant, fuel represents 60 to 70 per cent of the total cost of the power. It is obvious, therefore, that, by reducing the item representing so large a portion of the total cost by 60 per cent, a great saving in power cost can be effected. Investment costs for this type of plant are also lower. Condensers, circulating water intakes, piping, pumps and the building space required for them are all eliminated, with consequent saving in first cost.

Actual production and construction costs for back pressure plants are seldom available, and when they are published, are worth little for comparative purposes. Since each situation is an individual one as to the relationship between steam and power demands, requiring different treatment, the difficulty of getting back pressure plants on a comparable basis is easily seen. There is always a diversity of opinion as to what part of the total cost of producing steam and power is chargeable to power generation or to steam generation. On one side it may be contended that the cost of the power is entirely incremental, and so is the cost of investment for generating the power; on the other hand, the steam may be called the by-product. To separate the costs in this way is erroneous. Overall total cost for both products is the prime consideration, and in economic studies involving the supply of either steam or power from some competitive source, the cost of one should not be separated from the other.

The principal technical difficulty yet to be overcome in the design and application of this type of plant is the proper balancing of steam requirements with electrical requirements. It is possible to do this at any one point on the load curve by varying the back pressure, or, where the back pressure is fixed by process requirements, as is usually the case, by varying the initial steam pressure. The possibilities in this are illustrated by Fig. 58, which gives the power which can be generated by steam at varying initial and final pressures. But the ratio between the steam and electrical energy demands at the point of balancing does not always continue throughout the load period, so that at times the total steam required will produce more power than needed, and at other times the steam needed will not produce all the power required. For this reason, the actual economies ob-

tained seldom equal the theoretical. Many methods have been devised to overcome this difficulty.

The usual method is to design the plant for the maximum steam requirement with sufficient condensing capacity to take care of the unbalanced electric load. Steam demands above the supply from the turbine exhaust are taken care of directly from the boiler plant through reducing valves. Another method is to balance the steam and electric requirements within the power plant through the use of both motor and steam driven auxiliaries, together with a steam accumulator,[1] which stores the excess steam for use during a period of steam shortage.

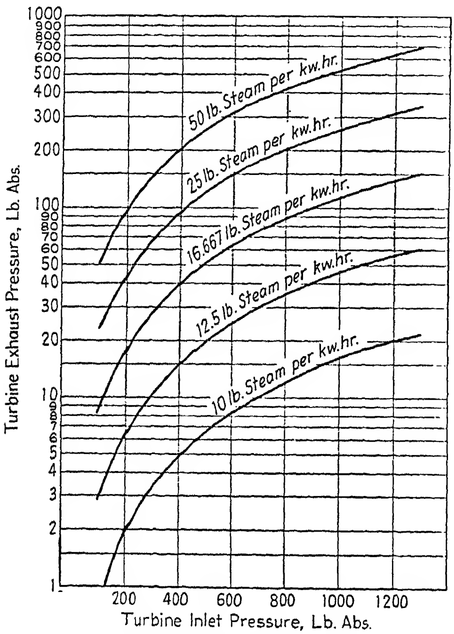


FIG. 58. Chart for calculating power available in steam at various initial and final pressures at 100 per cent turbine efficiency.

A method gaining in popularity, and from an overall economic standpoint the best, is interconnection with a utility system. In this arrangement, enough equipment for generating back pressure is installed to take care of the demand for steam at all times and the utility system is used as a reservoir from which energy is drawn or into which energy is pumped as the demands for steam and electric power vary. The full economic value of back pressure plants can be attained only by such cooperation between industries and utilities in developing such interconnections. Cooperation of this type is beginning to find application, although not as rapidly as the many economic situations warrant. Several practical examples are given in Chapter XVI.

217. Industrial Hydro Plants. — In certain of the primary industries, such as some of the chemical industries, certain paper

[1] See Chapter XII, Section 167.

mills, particularly newsprint mills, and the aluminum industry, the cost of power is one of the largest if not the largest single item of expense for the finished product. Such industries will locate where power can be obtained at minimum cost, in some cases even though it may necessitate shipping the raw materials several thousand miles. Consequently, companies in these industries search for and develop the most favorable water power sites, and locate their manufacturing plants at or near the point at which the power is developed.

The power plants themselves differ in no essential respect from hydro electric plants built for public utility use, except that installed capacity is usually on a lower basis in relation to available stream flow than it would be for public utility use. That is, the installation utilizes a smaller percentage of the total annual discharge of the stream than a public utility would. In the recent past, it has been found economical to interconnect many such plants with public utility companies because of the ability of the latter companies to utilize on their load curves a large percentage of the annual stream flow. Hence, many owners of such plants have found it advisable to enlarge their installations on an incremental cost basis (see Chapter X, Sections 151 to 154 inclusive) and sell to, or interchange power with, public utilities.

Some textile mills are situated on streams and rivers which supply them with water power for a part of their power requirements. Many such mills have found it advisable to make agreements with power companies covering both the purchase and sale of power. (See Chapter XVI, Sections 238 and 239.)

218. Oil Engine Industrial Power Plants. — The use of the oil engine in industrial plants has been increasing in recent years, and under certain conditions it furnishes the most economical source of power available. The economics of the use of oil engines in industrial plants has been fully treated in the preceding chapter.

219. Power Plant Paid for out of Savings. — Customers of power companies are frequently approached by manufacturers of oil engines and steam engines and by some contracting companies with a proposal for the customer to discontinue the purchase of central station power and to install a power plant of their own to be paid for out of the estimated savings. Sometimes the proposition may be stated thus: "You let us build a power plant. We will pay for the plant without any cost to you. You will pay us for the power at the same rates that you are now paying

for your power and at the end of 5 (or 10) years we will turn over the power plant to you without further payment, in good operating condition, and free of all debt."

That sounds like a very attractive proposition, and it is. Any proposition to pay for equipment out of savings has a strong appeal, and under many circumstances a contract on such a basis is advisable. If the proposed contract is really what the above quotation would indicate, and if the engine manufacturers or contractor will agree to give the customer the benefit of any rate reductions that may be made by the power company during the life of the contract, and if the power company's customer can assure himself that the service from the proposed plant will be just as reliable and satisfactory as that which he is obtaining from the power company, then he will be very foolish not to sign up. This is for the reason that he would be obtaining everything that the power company could give him, plus a present, after a term of years, of a complete power plant, so that thereafter the total cost of power to him would be merely the production cost in the power plant.

The overall economies in any given situation seldom permit of making a straight out and out contract on the basis outlined above. Consequently, the typical large power user should be inclined to be somewhat skeptical when approached with such a proposition, and to ponder such fundamental questions as the following before even looking into the proposition:

1. If the power company's rates are so excessive as to permit the engine manufacturer (or contractor) to build a power plant and liquidate it in 5 (or 10) years and make a profit on top of that, why should it not be still more profitable for me to build my own power plant?

2. The cost of money to the engine manufacturer or contractor must be very much higher than to the utility company; hence if the engine manufacturer can afford to build me a plant to be paid for out of savings, why could I not get a still better deal out of the power company on the same basis?

3. The cost of power from a big plant such as the power company has, must surely be less than the cost of power from a small plant such as the engine manufacturer (or contractor) proposes to build for me. Had I not better see if I can make them reduce the rates, and if they refuse had I not better appeal to the public service commission?

4. After all, will the proposition really accomplish for me what I want, namely, to obtain for me my requirements of dependable power at a lower total average cost than I will be able to get it for by continuing to purchase it from the power company?

5. Will the power plant, when it is turned over to me, be of any value to me in my business?

Although there are many situations in which the purchase of power or other equipment on an "out of savings basis" is an entirely advisable procedure, the shrewd business man will do well to investigate thoroughly not only the terms of the proposition herein discussed, but also all the pertinent conditions surrounding it. He will be a wise man if he engages as a consultant an engineer of national reputation in the power field, who has nothing to sell but services, to go into the situation thoroughly and advise him as to the most profitable course to pursue. Quite possibly such a procedure may result in a new deal which will be more advantageous to the power customer than either the basis on which power is now purchased or the proposal for securing his own plant to be paid for out of "savings."

CHAPTER XVI

PURCHASED POWER FOR INDUSTRIAL PLANTS

220. Competitive Nature of Power Company's Business. — The regulatory laws and commission rulings under which power companies do business are based on the theory that the business is a monopoly furnishing a service to the public for which every one must either pay the prescribed rates or do without. Because of their assumed monopolistic character, the power companies are permitted to have such rates as will allow them to make a fair return on the fair value of their property used and useful in the public service.

In theory, if the rates are higher than will provide this fair return, the regulating body will see that they are lowered; and contra, if the rates are too low to provide this fair return, the regulatory body will permit them to be increased. Practically, however, a power company may make a large investment to serve an industrial concern or a city, and a short time later the industrial concern or the city may build its own plant, whereupon the investment made by the power company becomes valueless and the power company can obtain no redress from the regulating body.

The theory is also defective in that practically all service furnished by the power company is competitive, sometimes within wide limits and sometimes within extremely narrow limits.

Domestic service is usually considered the least competitive of all. But even in the case of domestic lighting, the consumer may get his lighting by kerosene lights, gas or acetylene lights, or he may install his own electric power plant for lighting and other uses. Manufacturers of gasoline and oil engine storage battery sets stand ready to prove to him how he can get his electricity by such means for a cost of 2 to 5 cents per kwhr. Other domestic electric services are much more competitive. Electric refrigerators compete with gas, ice and solid CO_2 refrigerators. Electric ranges compete with gas, coal and oil ranges. Electric heating in the home competes with gas, coal and oil heating, and on the whole, not any too successfully.

For larger users of electric service, the competition becomes narrower and closer. Office buildings and apartment houses may and often do have their own power plants furnishing themselves with electric lights and power for elevators and other incidental service. Only half of the power utilized in factories is purchased from power companies. Even the smallest factory may and frequently does have its own prime movers. These fields are highly competitive, and in order to sell its service to these consumers, the power company must sell power at a lower rate than that at which the consumer can make it himself, or must sell a service which the consumer recognizes as having a higher value than the service which he himself can perform, or both.

221. Cost of Service Basis for Rates. — On the basis of the legal fiction that the power business is a monopoly, it would be only fair that each and every customer should pay for the service rendered him at its actual cost, including in cost a fair return on the value of the property used for that service. Seldom would any two customers have the same rate; the customer across the street from the power house would pay much less than the customer obtaining identical service five miles from the power house. No advocate of the cost of service basis for rates would carry out the theory to this logical but entirely impracticable extent, but the condition may be approached by dividing the territory into zones (or communities) and dividing all customers into classes.

In any given zone or community, consumers would pay the same rate for the same class of service. To determine the rates for any class of service in any zone, actual costs, including a fair return on the fair value of the property, would be allocated among the various classes of service on a predetermined basis. The advocates of the cost of service basis for rate making in its pure form are mostly theorists, and there is much controversy among them as to just how the cost should be allocated among the various classes of service. Nevertheless, the cost of service principle, with a more or less scientific allocation of costs among the various classes of service, has had an important influence in the development of the actual rate schedules now in use.

222. Value of Service Basis for Rates. — In all unregulated industries, the value of service basis controls all transactions. Thus, we do not worry about whether the oil company makes

a high return on its investment or no return at all. We want to buy good gasoline at the cheapest price obtainable. If one station sells it for 15 cents and another for 20 cents, we will buy the 15 cent gasoline unless we feel that in some way we obtain greater value by buying the 20 cent gasoline. If a man can buy a suit of clothes at one store for $40, and the same suit at another store for $30, he will buy the $30 suit unless in some way he feels that he obtains greater value by buying the $40 suit. Of course, in the long run, the oil company and the clothing company must sell for not less than cost including a fair return on investment; otherwise, they will not long continue in business. If the clothing company, for instance, makes a very large return on its investment, it will, assuming sound business judgment, reduce the price of its suits, promoting the use of more suits by its customers and thus making a greater total profit or return on investment.

The advocates of the value of service basis for rate making maintain that power companies should be guided by the same general principle. Thus, electricity for lighting has a relatively high value in the mind of the average man. Not many people would use kerosene lamps or install their own lighting plant even if the rates for electricity for lighting were much higher than they are. Thus the public sets a high value on central station electric power for lighting, and, according to this principle of the value of the service rendered, rates for electric lighting should be much higher than for other electric services on which the public does not place so high a value.

At the other extreme is the industrial concern which requires a large amount of electric power for manufacturing purposes. It can build its own power plant and secure just as reliable service as the central station can furnish. The value of the service which the power company can render is here relatively low, and may be close to or even below the actual incremental cost of furnishing the service. Under the value of service rendered principle, the rates for this class of service may approach the incremental cost of furnishing the service. Of course, on the overall average, the power company must obtain a revenue which is equal to cost including a fair return on investment, or it cannot long remain in business.

223. Actual Basis of Rates. — Most actual rate schedules are based on a mixture of these two principles; that is, both cost and

value of service are properly elements in determining rate schedules. Regulating commissions generally recognize the value of service principle as an element in rate making, but insist that the net overall return to the power company shall not exceed a fair return on the value of the property used and useful in the public interest. Rate schedules usually contain promotional features, because it is to the interest of both customers and company to increase use and thus permit a decrease in unit costs and rates. For low value classes of service, such as heating and large power use, it may pay a power company to make rates which are not greatly in excess of the incremental cost of furnishing such additional services.

Generally speaking, any rate which will result in a material and permanent increase in the net income of the company is advisable. Thus, it may be advisable to take on a large power load even though the revenue therefrom is less than the total average cost of furnishing service to power customers, so long as the revenue obtained is materially above the incremental cost of furnishing such service. Such a policy is in the interest of all customers, as by increasing net income the power company will soon be able to make rate reductions to other classes of customers.

224. Rate Schedules. — As ideas have varied greatly between different power companies and different regulating bodies as to the proper basis for rate schedules, it is not surprising to find a wide variation not only in actual rates, which might be expected from changing conditions and costs, but also in the manner in which different classes of services are charged for. During recent years, efforts have been made to simplify the rate schedules of many companies, but in most cases further simplification is feasible and desirable. The rate book of many power companies forms a respectable volume in itself, and one may need a guide to find his way among the various schedules.

Rate schedules for domestic service and small power should be simple in order to remove, as far as possible, friction due to misunderstanding by the large number of consumers involved in these classes of service; but rates for large power customers with which we are herein chiefly concerned are necessarily much more complicated in order to meet in the most efficient and economical manner the needs of particular groups of customers. As each bill is of considerable size, it does not matter so much if

it takes some time to prepare and check the monthly billing. Rates for large power users are usually either of the Wright demand rate type or the block Hopkinson demand rate type, or sometimes a combination of these two types. Occasionally the flat demand rate is used.

225. Flat Demand Rate. — The flat demand rate is occasionally found in some hydro electric companies which are installed on such a basis that it is practicable for them to operate all their capacity practically at 100 per cent capacity factor throughout the year. It is probably the simplest rate in existence, as power is sold at so much per kilowatt-year or horsepower-year, without any separate charge for energy. Thus, if the charge is $20 per kw-yr and the customer's plant is capable of using 1000 kw, the contract might be for 1000 kw at $20 a year, or $20,000 per year regardless of the amount of energy used. Some chemical companies pay for their power on this basis.

226. Wright Demand Rate. — In the Wright demand rate system of charging, the customer's demand is first determined. (Sometimes it is taken as 100 per cent or less of the connected load.) On the monthly bill, the customer is then charged a certain maximum price per kilowatt-hour for a certain number of hours' use of demand, and then, on the block system, another lesser price per kilowatt-hour for so many hours' use of demand, and so on down.

Following is an example of a Wright demand rate schedule:

Available for small power users — no lighting under this schedule

5 cents per kwhr for first 50 hours' use of demand per month.
3 cents per kwhr for next 50 hours' use of demand per month.
2 cents per kwhr for next 50 hours' use of demand per month.
1 cent per kwhr for all excess.
Demand shall be considered as 75 per cent of the connected load.
Delayed payment penalty: 5 per cent after 10 days.
Power factor penalty: If power factor is less than that specified below, the demand for billing purposes shall be adjusted to the power factor specified.
80 per cent for demands less than 50 kw.
90 per cent for demands of 50 to 1000 kw.
95 per cent for demands of over 1000 kw.
Minimum charge: 50 cents per kw of connected load, but not less than $10.00.

227. Hopkinson Demand Rate. — Under the Hopkinson demand rate method of charging, there is a charge for the estimated

or measured demand or for the connected load and also another charge based on the quantity of energy used. A very simple schedule under this type of rate would be the following:

Demand charge: $1 per kw of connected load per month.
Energy charge: plus 6 mills per kwhr for all energy used.
Minimum demand charge: $100 per month.

There is also usually a power factor clause similar to that given in Section 228 as well as a penalty or discount clause to promote prompt payment of bills.

228. Block Hopkinson Demand Rate. — The energy charge or the demand charge or both may be blocked in the Hopkinson rate. An example of such a rate is the following:

Demand charge: $1.50 per kw of demand per month for first 500 kw and $1.00 per kw for all additional

Plus an energy charge of:

3.5	cents	per kwhr	for first	5,000	kwhr	per month
2.0	"	"	" next	10,000	"	"
1.5	"	"	" next	15,000	"	"
1.25	"	"	" next	20,000	"	"
1.00	"	"	" next	100,000	"	"
0.9	"	"	" next	350,000	"	"
0.8	"	"	" all excess			

Available for power installations of not less than 100 kw, including lighting, provided lighting does not exceed 20 per cent of total connected load.

Determination of demand: Average of the three highest 15 minute integrated demands during the month. Company reserves the right to measure the power factor, in which case the demand will be the demand as determined above or 80 per cent of the average kilovolt-amperes during these peak periods, whichever is higher. Demand for billing purposes to be not less than 50 per cent of the highest billing demand for any of the preceding 11 months, nor less than 100 kw.

Prompt payment discount: A discount of 7 per cent will be allowed for payment of the bill within 10 days of the date rendered where the net bill exceeds $5000.

Primary discount: A discount of 10 per cent will be allowed if energy is purchased at 11,000 to 22,000 volts and the customer furnishes all transformer and substation equipment.

229. Mixed Demand Rate. — This is a system of charging large power customers, involving features of both the Wright demand rate and the block Hopkinson rate, which has recently come into vogue. Both demand charges and energy charges are blocked, but the energy charges are blocked in hours' use of demand. The scheme makes it particularly advantageous for

the customer so to regulate his operation as to secure the highest practicable load factor on billing demand.

A rate of this character is given in the following schedule of the Union Electric Light and Power Company of St. Louis:

Service for 3 years or more for not less than 150 kw — applies to wholesale untransformed service.

(*a*) Demand charge (per year)

$20.00	for each kilowatt of demand of the first	200 kw
$15.00	" " " " next	800 "
$12.00	" " " in excess of	1000 "

Payable in equal monthly installments plus the following:

(*b*) Energy charge

For the first	300	hours' use of billing demand per month	0.7¢ per kwhr
" next	100	" " " "	0.6¢ "
" next	100	" " " "	0.5¢ "
Excess over	500	" " " "	0.4¢ "

The determination of billing demand is on a basis similar to that stated in Section 230 on off peak adjustment of billing demand. Other clauses provide for the usual coal adjustment (Section 231) and discount for prompt payment of bills and prohibit the resale of service. In this particular schedule there is no power factor clause, although in many instances such a clause might be desirable.

230. Off Peak Adjustment in Billing Demand. — Power companies must supply generating, transmission and distribution facilities to take care of peak loads which occur during certain hours of the day and certain months of the year. Consequently, a material increase of load in off peak hours and off peak seasons would not increase the power company's fixed charges. Accordingly, many large power contracts have a clause providing that the demand shall be measured during hours of the day when the system peak occurs and for certain months during which the load is heavy. Thus, such a clause might state that the billing demand shall be the highest actual demand (actual 15 minute integrated peak) occurring between the hours of 7 A.M. and 10 P.M. during the months of November to February inclusive, but shall not be less than 50 per cent of the highest actual demand occurring at any time, nor less than 75 per cent of the actual demand occurring between the hours of 7 A.M. and 10 P.M. during any month of the year. Once established, the billing demand shall rule until exceeded, or for the succeeding 11 months, at which time a new demand period shall start.

Such a clause is sometimes very valuable to both power company and customer. Industries and operations which can so arrange matters that they can make their peak loads come in the off peak periods specified are able to obtain very low overall rates for power. In some cases load factor on billing demand may exceed 100 per cent for several months. The power company benefits by evening out its load curve and by being able to secure business otherwise unobtainable. For instance, in one case a 1000 kw water company pumping load was obtained solely because of the advantages inherent in a clause of this nature.

231. Coal Adjustment Clauses. — It is also quite usual to include in large power contracts a coal adjustment clause so that, if the price of coal goes down, the customer will obtain a corresponding decrease in his energy charge, and if it goes up, he will pay a corresponding increase. This clause puts the customer on a basis relative to variation in fuel costs comparable to that which he would be on if he owned his own plant.

232. Better Knowledge of Rate Schedules Necessary by Customer. — Some large power customers are quite ignorant of the rate schedules under which they are buying their power, and instances are not rare where no one in the customer's organization is sufficiently familiar with the rate schedule to check the monthly bill completely. For instance, in one case, incorrect monthly billings had been innocently made by the power company for several years by reason of a faulty interpretation of the schedule. Sometimes the sums billed were more than they should have been, and at other times less. The customer, however, did not discover the error until it was pointed out to him by the power company. The large power customer should make himself thoroughly familiar not only with the schedule of power rates under which he is purchasing power, but also with all other power schedules of the power company.

Quite often the schedule under which he is obtaining service might have been admirably suited to his needs at the time he first became a customer, but the changing condition of his operations or the filing of additional power rate schedules by the power company may have entirely changed the situation, so that at the present time he could make a material saving by taking power under some other schedule.

By keeping in constant contact with the power company's

power salesman, he will usually maintain himself in a position to take advantage of many savings which might be made. The efficient power salesman is always alert to increase the use of central station power, and he knows that if the customer gets his power for less he will in the long run use more of it. Often also the power salesman will be able to point out ways in which the customer can economically use more power in his manufacturing processes without greatly affecting the demand charge.

Especially in cases where service is purchased under a schedule having an off peak adjustment clause similar to that described in Section 230, it is frequently possible so to arrange certain features of the customer's manufacturing operations as to make his peak come in the specified off peak period and thus secure a very high load factor on billing demand, and make his overall cost of power much lower. For instance, one customer saved a material sum during the year by placing on his demand meter an automatic relay device so that when an actual demand was approached which would affect the billing demand, certain services which by their nature could operate intermittently were automatically cut off.

233. Power Company Investigation to Determine Needs of Customer. — The power salesman of the utility company is, or should be, in constant touch with all power customers; and as a first step in determining the most economical means of meeting his increasing load requirements, the manufacturer usually permits the power salesman to make an investigation of his needs.

The various rate schedules of the power companies are compiled with the object of fulfilling the varying requirements of different classes of power customers. For any given customer, there is usually a rate schedule which meets his particular needs and gives him an overall cost of power lower than any other rate schedule. Furthermore, in the case of large power customers, it is usually not difficult for a power company to secure the approval of the state regulating body for a new rate schedule which may suit the particular requirements of the customer much better than existing schedules. The power company's power salesman should be given an opportunity to have a complete survey made of the prospective power customer's needs, as a result of which he should be able to point out to the prospective customer the most advantageous existing rate schedule to meet his needs or to help him obtain such a one.

Power salesmen are interested primarily in selling more power; but on the other hand, progressive power companies have learned that ultimately their interests and the interests of the manufacturing concerns of their territory are identical. In other words, in the long run it is not to the interest of the power company to sell power to a manufacturer when it is more economical for the manufacturer to make it himself. Practically every power company has in many instances advised prospective customers to the effect that it will be unable to make a rate which will enable them to purchase power at as low a rate as they can make it.

234. Advisability of Manufacturer's Engaging Consultant. — Many industrial concerns have competent power engineers on their engineering staffs, but as a rule, these engineers do not have as broad a knowledge of the economics of power supply or of the vagaries of rates as the staff men of the power company, and consequently the industrial concern is frequently at a considerable disadvantage in negotiations. Most industrial concerns have firms of engineers or engineering companies to whom they are in the habit of going in connection with improvements and extensions to their manufacturing plants, and also their power plants. Quite naturally they turn to such firms or engineering companies for advice when a power company makes a proposition for selling power to the industrial concern.

Advice obtained in such a quarter may or may not be the best and most unprejudiced obtainable. It should be remembered that an engineering firm or company which derives its principal revenue from designing and supervising the construction of plants may have an unconscious but nevertheless real predilection in favor of building power plants as an alternative to purchasing power. If the amount of money involved is material, the industrial concern should, in addition to utilizing its ordinary engineering services, engage a consulting engineer of national reputation in the power field who has nothing to sell except his own personal services. Such a consultant should be allowed to go into the problem thoroughly and determine the most economical course for the industrial concern to pursue.

235. Interconnection between Power Plants of Manufacturer and Utility. — When an industrial concern and a power company propose to interconnect their power plants for the exchange of power and energy, the basis on which the interchange shall be made is sometimes the subject of much argument. The indus-

trial engineer may argue that his electrical energy is just as good as the power company's, and that when the power company takes his energy it should pay for it at the same price that he would pay for the power company's energy. If the contract is on a "when, as and if basis," this is fair enough to both parties, but often the service required of the power company under such an interconnection arrangement is quite different from that required of the industrial concern.

Usually the power company must stand ready to deliver energy to the industrial concern on demand in such quantities as the industrial concern may require. On the other hand, the industrial concern usually proposes to deliver energy to the power company at times when it does not require it itself, and frequently in quantities determined by itself. In the case of hydro energy, the power company will probably have a surplus at the same time as the manufacturer, and for the power company to purchase such energy often means that it must waste energy at its own hydro plants.

Under the conditions outlined, the power company must have an investment in capacity ready to serve the manufacturer, and is thus entitled to a demand charge, whereas the manufacturer makes no investment for the benefit of his customer, the power company, and cannot guarantee to meet any specific demand for service which the power company may make on him. He is therefore not entitled to receive any payment for demand under the conditions herein assumed, and the value of the energy which he furnishes to the power company may be even less than the increment cost of steam generated energy in the plants of the power company.

In such cases, conflicting viewpoints sometimes prevent any contract from being arrived at even though the economics of the situation might make some basis of cooperation mutually advantageous. Such a condition emphasizes the desirability of engaging a consultant as suggested in Section 234, who because of his broader knowledge and experience may succeed in reconciling the opposing viewpoints and working out some basis of agreement profitable to both parties.

There are various bases on which mutually advantageous arrangements can be worked out according to the particular conditions, some of which are suggested in Sections 239, 240 and 241.

236. Use of Old Steam Plants to Reduce Demand Charges. — Often when an industrial concern decides to purchase central station electric service, it already has a power plant of its own, which up to that time has served all its needs for power in a fairly satisfactory manner. The decision to purchase central station service is reached as an alternative to the extension of the old steam plant or the construction of a new one to supply the increasing load. Frequently the industry requires some process steam so that the old boiler plant must be kept in service anyway. Under such circumstances, it usually pays to retain in serviceable condition the old generating equipment, even though the average overall unit cost of purchased power is materially less than the production cost in the old steam plant of the industrial concern.

The old steam plant may then be used to keep the demand charge at a minimum. This use of the old steam plant is particularly profitable when the rate schedule under which power is purchased contains a clause providing for an off peak adjustment in billing demand as described in Section 230. To obtain full advantage of this opportunity for utilizing the old steam plant in this manner to secure a lower total cost of power supply requires a thorough knowledge of the power company schedules and of the load and plant characteristics of the industrial concern. It is believed that, if industrial concerns in general fully realized the manner in which their old steam plant could be utilized in connection with purchased power to reduce the total cost of their power supply, more industrial concerns would find it economically advantageous to purchase a part of their power requirements from a power company.

237. Gasoline or Oil Engines for Cutting Demand Charges. — Manufacturers who have no need of process steam and who do not have an old steam plant may find it economically advantageous to install gasoline or oil engines in connection with their contract for purchasing power in order to keep down their billing demand, as discussed in the previous section. In fact, in some cases a straight comparison between the cost of purchased power and power from a plant to be built and owned by the industrial might show a considerable margin in favor of the latter method; but on the other hand, if power is purchased and a relatively small capacity gasoline engine generating set installed for the purpose of cutting demand, the net result might be materially in

favor of purchased power. This might be true even though the cost of energy from the gasoline engine set, which would be operated only occasionally, was greatly in excess of the average cost of either purchased or manufactured power.

238. Use of Manufacturer's Hydro Plants to Cut Cost of Purchased Power. — Many factories were located on streams and rivers where they installed their own hydro plants for furnishing power for all mill operations. At first the minimum stream flow available was sufficient for all power requirements, but as the factories grew, this was no longer the case, and they were compelled either to add steam plants or to purchase additional power from power companies. Frequently these relatively small hydro plants are not operated in a manner to secure the lowest total cost of power. If, as is usual, some pondage is available, such plants can be operated to cut the billing demand on purchased power as in the old steam plant discussed in Section 236.

During times when the mill is not running hydro power is wasted, and it is also frequently wasted in large quantities at times of high water when the mill is running. If a contract is made for central station power, the power company will usually agree to buy from the manufacturer all surplus hydro energy which cannot be utilized in the mill operations, often at a price equal to the marginal cost of steam generated energy. The credit thus secured by the manufacturer may be a very material sum offsetting his gross power bill. Therefore, any manufacturer who has a hydro plant and is considering the installation of a steam plant to take care of his increasing load will do well also to investigate thoroughly purchasing central station power, because if it is utilized in conjunction with his old hydro plant it may well be that the net cost will be very much less than is apparent from a study of rate schedules.

239. Manufacturers May Both Sell and Purchase Power. — In many cases when, on first investigation, it appears that it is not going to prove economical for an industrial concern to purchase central station service, it is feasible to work out a scheme for interchanging power and energy between the central station and the manufacturer's power plant on a basis which will prove profitable to both parties.

Assume that a certain manufacturer has a 10,000 kw steam plant consisting of two 5000 kw units, and does not at the present time purchase any power from the power company or have any

connection to its lines. The manufacturer knows that next year his peak load will reach 8000 kw, and therefore, in order to have adequate reserve to be sure that his operations will not be interrupted, he contemplates adding an additional 5000 kw unit. His power plant, although not in any sense an antiquated one, has a very much higher production cost than the large central station plants of the utility company. The next year the utility company will also have to install additional capacity.

If the power company were to acquire the entire load of the manufacturer and thus shut down the manufacturer's power plant, it would on this account have to install, perhaps, 9000 kw of additional capacity. If, however, the power company could utilize the manufacturer's power plant over its seasonal peak or have it available as reserve capacity, it would not have to install this additional capacity.

Consequently, a contract is worked out under the terms of which the manufacturer buys all his requirements of power and energy from the power company on, say, a block Hopkinson rate schedule, and the power company in turn agrees to pay the manufacturer so much per kilowatt per year for the capacity of his existing steam plant plus an energy price for any energy which the power company may ask the manufacturer to generate for it. A desirable modification of this scheme is for the power company actually to lease the manufacturer's power plant for a term of years. This arrangement is more desirable because the manufacturer thus gets rid of the responsibility of maintaining the plant, and the power company, having the plant in its own control, can be more sure that it will be ready to operate on the system peak when required.

For such a proposition to be attractive to the manufacturer, the total annual net cost of service after deducting payments made by the power company to the manufacturer must be less than the total annual operating cost of the manufacturer's enlarged plant plus the fixed charges on the proposed new unit.

240. Process Steam and By-Product Power. — There are many industrial concerns whose requirements for process steam exceed their requirements for power. Under such conditions, power is a by-product. If the management of such a concern is approached by a power salesman, he is usually told that the industrial concern has more power than it needs and that, therefore, there is no chance that it would be interested. How-

ever, such situations frequently present excellent opportunities for both the power company and the industrial concern to make material savings.

The process steam requirements of the industrial concern may greatly exceed its steam requirements for power, and in many cases it could install additional generating equipment and produce more electrical energy on a marginal cost basis which the industrial concern frequently could afford to sell to the power company at a price less than the power company's replacement cost.

When under the conditions outlined above the industrial concern is contemplating the construction of a new steam plant, there exists a promising opportunity for a cooperative arrangement between the industrial concern and the power company. Under such an arrangement, the plant may be owned jointly or by the industrial concern or by the utility company.

If the proposed plant would be useful to the power company even if the industrial concern should go out of business, there may be a material advantage to both parties in having the plant owned by the power company, largely because the average cost of money for an industrial concern is higher than for a public utility. Owing to the greater uncertainty of profits, money invested in industrial concerns must on the average earn a bigger return. Few industrial concerns would invest their capital in new factories unless they expected to make a net return on the investment of at least 10 to 15 per cent. The power company, on the other hand, by reason of the greater stability of its business, can expect to make a net average return on investment of only 7 to 8 per cent. In fact, if it is much more than 8 per cent, the regulating body will usually find some way of reducing it.

Consequently, if an industrial concern builds a steam plant, it should figure on making as great a net rate of return on the money invested in it as it makes on the rest of its business. Thus, it is to the advantage of the industrial concern to purchase power and steam if this can be done at a cost showing a material annual saving over the total annual cost on an alternative steam plant of its own with the price of money taken at the average net rate of return which it expects to realize on its business as a whole.

Recently on this basis power companies have built a number of joint service steam plants at or close to the industrial concern

primarily served therefrom. Steam is produced at high pressure and passed through turbines, and is then delivered for process use to the industrial concern. The industrial concern buys its steam and power requirements, and the power company absorbs the surplus electric power in its system. The overall advantage of the scheme is manifest.

Plants for securing the advantages outlined above have recently been built at Baton Rouge, La.; Rochester, N. Y.; Deepwater, N. J.; Detroit, Mich., and in other places.

The Louisiana Steam Products Company, Baton Rouge, La. (a subsidiary of Engineers Public Service Company), has a plant supplying steam requirements to a Standard Oil refinery nearby. Steam at 670 lb and 750° F is delivered to three 15,000 kw turbines exhausting to process at 141 lb.

At Deepwater, N. J., on the Delaware River near Philadelphia, there is a plant owned half by the Atlantic City Electric Company and half by the Philadelphia Electric Company, which furnishes process steam and power to E. I. du Pont de Nemours and Company nearby. There are two turbine units of 53,000 kw capacity each, and one of 12,500 kw capacity, taking steam at 1200 lb and 750° F. The 12,500 kw unit is identical with the high pressure stage of the two large units, but operates non-condensing. Most of the electrical energy from this unit goes to du Pont. The exhaust from this unit at 250 lb to 450 lb pressure, depending on steam demand, then goes to evaporators, from which it is returned as distilled feed water to the boilers. The vapor produced in the evaporators is superheated to 440° F by the 1200 lb steam, and is then delivered to du Pont as process steam.

241. Use of By-Product Fuel by Manufacturers. — When an industrial concern uses by-product fuel and also uses process steam and power on a relatively high load factor, it is usually uneconomical for it to consider the purchase of power when all three of these factors approximate a balance. However, if more by-product fuel is available than enough to make the steam and power required, or if process steam requirements exceed power requirements, the operation is out of balance and a situation is created analogous to the one described in Section 240. An opportunity may thus exist for making a mutually profitable agreement between the power company and the industrial concern.

INDEX

O

P

Y